4. LESSONS LEARNED

This discussion includes information on lessons learned the California biomass energy industry and reported on in 2000, a brief update on the California situation, lessons from commercial biopower plants, lessons from selected DOE demonstration projects, and a short summary of the issues considered most critical for commercial success.

The California Biomass Energy Industry[1]

California has one of the largest and most diverse biomass energy industries in the world. At its peak, the California biomass energy industry produced almost 4.5 billion kilowatt hours per year of electricity and provided a beneficial use outlet for more than 10 million tons per year of the state's solid wastes. The peak, however, occurred during the early 1990s. Since that time, a quarter of the biomass energy facilities have agreed to buyouts of their power sales contracts and terminated operations, while others have reduced their operations. This has occurred because of concerns about the long-term viability of these facilities in a competitive, deregulated electricity market. This uncertainty casts an ominous cloud over the future viability of biomass energy generation in California.

Development of the California Biomass Energy Industry

California's diversity and extent of agriculture and forestry industries are unrivaled in the world. Both activities produce large quantities of solid wastes, many of which are biomass residues that can be used as fuel. Before the federal Public Utilities Regulatory Policy Act (PURPA) was passed in 1978 only a few biomass-fired boilers were operating in California, and little electricity was being generated from biomass. Most of the state's biomass wastes were being disposed of, mainly by open burning and landfill burial. PURPA changed all that by requiring that electric utility companies buy privately produced power at their "avoided cost" of generation. PURPA created the market context that allowed for the development of the independent power industry in the United States. High avoided cost rates in many areas of the country, and favorable federal tax treatment for investments in renewable energy projects, provided the motivation for its development.

California was a leader in the development of renewable energy generating facilities. A combination of circumstances, including a high growth rate in electricity demand, oil dependence, and rising concerns about environmental deterioration, led to the implementation of state energy policies that were highly conducive to the development of renewable energy sources. These policies and opportunities stimulated a major development of biomass energy generating capacity in the state. During a period of less than 15 years (roughly 1980–1993), nearly 1,000 MW of biomass generating capacity were placed into service. The biomass energy sector expanded from an outlet for a small quantity of the state's wood processing residues to an essential component of the state's solid-waste disposal infrastructure. Today the California biomass energy industry provides a beneficial use for almost 6.5 million tons of the state's solid wastes. However, it has a highly uncertain future. The expiration of fixed-price power sales provisions for many facilities, combined with the deregulation of the electric utility industry and the current availability of cheap natural gas, threaten its long-term economic viability.

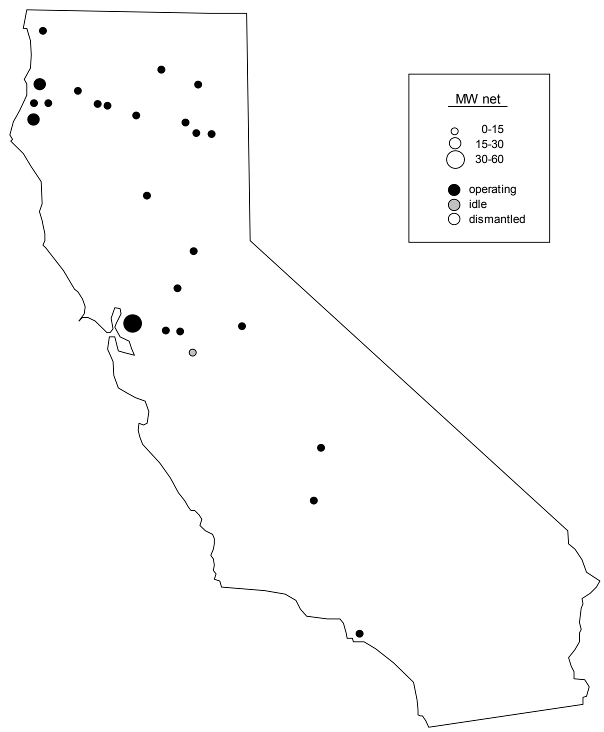
The 1980s: Decade of Growth

The early 1980s mark the nascent period for the California biomass energy industry. During this period, several pioneering biomass energy generating facilities were built and placed into service. The early

[1]Excerpted from: Morris, G. (2000) "Biomass Energy Production in California: The Case for a Biomass Policy Initiative," NREL/SR-570-28805, National Renewable Energy Laboratory, Golden, CO, November.

facilities tended to be small, generally 2-10 MW, and most were associated with sawmills or food processing operations that were looking for beneficial use outlets for their wastes. Figure 4.1 shows a map of the state's operating biomass energy facilities at the end of 1985.

Figure 4.1: California Biomass Power Plants, 1985



Also during the early 1980s, the California electric utility companies developed standard offer contracts for power purchases from independent generators. These contracts had particularly favorable provisions for renewable energy projects. A great deal of biomass project development activity was initiated during this period, which led to an explosion of new facility openings during the second half of the decade.

The California biomass energy industry became an important part of the state's electricity supply infrastructure and its waste disposal infrastructures during the second half of the 1980s. The incentives for renewable energy development that were offered during the first half of the decade led to the opening of 33 new biomass generating facilities between 1985 and 1990. A few of the pioneering facilities were shut down during this period, but the state's total operating biomass energy capacity grew by more than 650 MW. The average size of the facilities brought on line during this period was about 17.5 MW; the largest facilities were 50 MW. The explosive growth of biomass generating capacity culminated in 1990, when 11 new facilities were commissioned in a single year, adding 232 MW of biomass generating capacity to the state's electricity supply. Figure 4.2 graphically illustrates the development of the biomass energy generating industry in California from 1980 to the present. Figure 4.3 shows a map of the state's installed biomass power infrastructure as of the end of 1990.

Figure 4.2

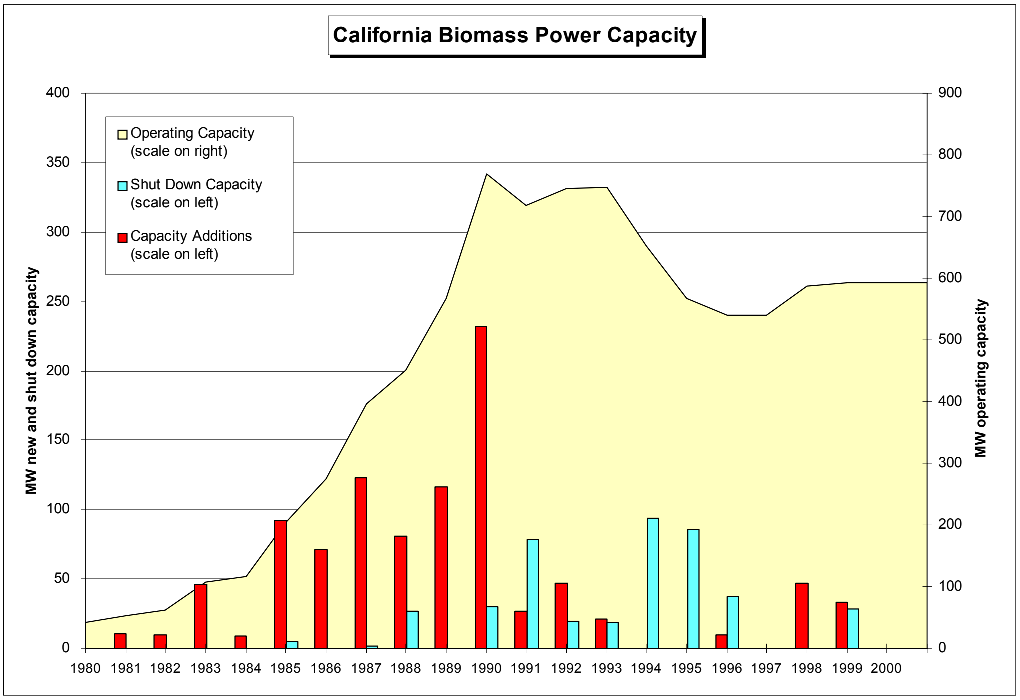
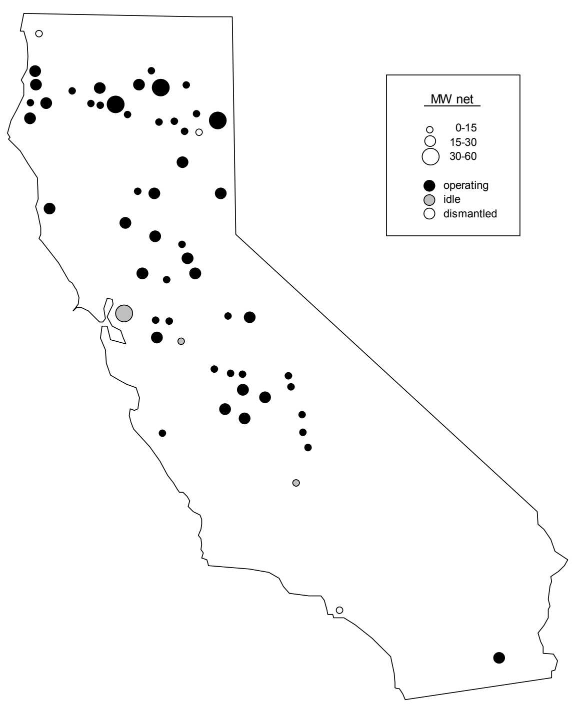


Figure 4.3: California Biomass Power Plants, 1990



Many of the facilities that entered service during the late 1980s had Interim Standard Offer No. 4 (SO#4) power purchase agreements (PPAs) with the state's two major electric utility companies, Pacific Gas and Electric Co. (PG&E) and Southern California Edison (SCE) Co. The SO#4s were the most favorable contracts available to independent project developers in California. These contracts were available for signing only during 1984 and 1985, and contract holders were given 5 years to bring their facilities into operation. The most significant feature of the SO#4s was an option for energy sales from electricity generated from renewable resources to be based on a forecasted schedule of energy prices for the first 10 years of facility operations, rather than being subject to fluctuating, short-term prices. These schedules were based on the high avoided cost rates then in effect (5¢–6¢/kWh), and an expectation that rates would remain high throughout the terms of the agreements. At the completion of the 10-year fixed price period generators are compensated based on the then current market price, which is called the short-run avoided cost (SRAC).

The SO#4 power purchase provisions for biomass energy facilities were designed to encourage the development of base-load generators that would provide the power grid with dependable generating capacity during peak demand periods, which are summer weekday afternoons. Most of the contracts were written with 30-year firm capacity terms of performance, which obligate biomass facilities to generate at their contract capacity at least 80% of the time during defined peak hours of the year, for the entire term of the agreement. Payments to generators for providing firm capacity are levelized over the contract term, and confer a significant liability on generators that do not operate for the entirety of the agreements.

The second half of the 1980s was also significant for a reversal in world oil markets. World oil prices, which had remained high since the price explosions of the 1970s, collapsed during the period 1985-1986. SRACs in California fell by 50% over an 18- month period. Most biomass power plants, however, were immune to the decline in SRAC rates during this period, because they received fixed-schedule rates under their contracts, based on early 1980s energy prices.

The attention of the biomass generating facilities focused instead on a looming crisis in the biomass fuels market. As the state's installed biomass generating capacity grew rapidly during the later half of the 1980s, the demand for fuel soon overwhelmed the readily available supply. Virtually all sawmill and food processing residues that did not have higher valued uses were being sold into the fuel market, and still there was a significant deficit between biomass supply and demand. Numerous efforts were under way to develop technologies to produce biomass fuels from new sources of supply, such as agricultural prunings, agricultural field residues, forestry residues, and urban waste wood, with rising fuel prices providing the incentive. The state's biomass fuels crisis peaked in 1990 with average prices topping $40/bdt[2] of fuel, and spot prices reaching $60/bdt or higher. Moreover, several major new facilities were approaching the completion of construction, and there was a fear that biomass fuel prices might continue to rise.

The 1990s: Maturity and Consolidation

At the end of 1990, more than 770 MW of biomass energy generating capacity were operating in California, and an additional 100 MW of capacity were in advanced stages of construction. The early years of the 1990s saw the state's biomass energy industry stabilize at a level of about 750 MW of operating capacity. During this period, the startup of the last of the SO#4 facilities was balanced by the retirement of several pre-SO#4 facilities, many of which had serious design flaws or operational problems. 1993 also saw the first retirement and dismantling of a facility with an SO#4 contract. This

[2]bdt = bone-dry ton equivalent, a unit of measure used for biomass fuels. A bdt refers to an amount of material that contains a ton of moisture-free biomass fiber. Generally, 1 bdt is equivalent to 1.2–2.4 actual, or green tons of biomass. In this discussion on California the term ton used alone refers to green tons of biomass, and bdt refers to bone-dry ton equivalents of biomass.

was a facility that had been beset with technical and operational problems that prevented its profitable operation.

The California biomass fuels market also stabilized during the early 1990s, with average market prices settling at a level of about $37.50/bdt, at an average consumption level of approximately 9 million tons per year. This stability was reached despite the beginning, in 1990, of a long-term decline in the state's wood products industry, which was caused by a combination of environmental restrictions and economic conditions. This is significant because wood processing residues are the lowest-cost biomass fuels in the state. By the end of 1993, the biomass energy industry appeared to have attained a level of maturity, and a workable equilibrium between fuel supply and fuel demand had been established. Although there were winners and losers, the California biomass energy industry as a whole successfully weathered the storm of the fuel crisis that marked the beginning of the decade.

The stability, however, was short lived. In April 1994 the California Pubic Utilities Commission (CPUC) issued its landmark *Blue Book* proposal for restructuring the state's regulated electric utility industry (CPUC 1994). The *Blue Book* proposal provided for competition among generating sources on the basis of price alone, without regard to non-market factors such as resource diversity and environmental impact. This represented a major threat to biomass energy generation. Because of the low density of biomass fuels and the resultant high handling and transportation costs, the relatively small size of biomass generating facilities, and the low cost of natural gas, the cost of power production from biomass was inherently higher than the cost of power generation using natural gas. Competition based on price factors alone would not favor biomass energy generation.

The most immediate effect of the *Blue Book* restructuring proposal for the biomass energy industry was that it provided an incentive for the state's regulated electric utility companies to buy out the SO#4 PPAs held by the biomass generators in their service territories. Many biomass generators were receptive to these offers because of their concern about their own long-term liabilities to the utility companies in connection with the firm-capacity obligations in their contracts. Over the next 3 years 17 biomass facilities, rated collectively at more than 215 MW, accepted buyout offers and shut down operations.[3] Unlike in earlier years, when only marginal facilities were closed, most of the facilities that shut down following the issuing of the *Blue Book* proposal were first-rate facilities that had been operating efficiently and profitably until the buyouts of their PPAs.

Annual biomass fuel use in the state shrank by 37% during the 2 years following the appearance of the *Blue Book* proposal. More than 3 million tons/year of biomass residues that were being used for energy production in the early 1990s were returned to open burning and landfilling for disposal. In addition, at its peak the state's biomass industry was supporting forest treatment operations on approximately 60,000 acres/year of forest land that was not otherwise being commercially harvested or treated. These treatments reduce the risk of destructive wildfires and improve the health and productivity of the thinned forest. With the retraction in the demand for biomass fuels the amount of this type of forest treatment activity has declined dramatically.

The CPUC's original restructuring proposal underwent a process of refinement that lasted for more than two years. By the summer of 1996 the CPUC had acknowledged the desirability of incorporating environmental factors into the choice of energy sources, and embraced the concept of a minimum purchase requirement for renewable energy sources. A working group made up of the utility companies,

[3]One of the 17 facilities was sold and restarted during this period. This facility was purchased by a buyer who intended to operate it at about one-half of its rated capacity, supplying steam and electricity to an over-the-fence industrial customer. Two other shut-down facilities, which only sold out the remaining fixed-price period of their PPAs, have since restarted. The other 14 facilities that were shut down during this period remain shut down today.

independent power generators, and public interest groups worked on formulating a consensus proposal to the CPUC to implement a minimum renewables purchase requirement for California's regulated electric utility sector (Morris et al. 1996). The biomass industry, which pioneered the concept of a renewables portfolio standard (RPS), played a key role in this process.

In late August 1996, just before the end of the state legislative session, the California legislature formulated its own electric utility restructuring program, superseding the efforts of the CPUC. The legislation that emerged, AB 1890, included a program of short-term support for renewable energy during the 4-year transition period (1998-2001) to full implementation of restructuring. However, no long-term support program for renewables was included. AB 1890 explicitly recognized the special waste disposal benefits associated with biomass energy in California. The legislation directed the California Environmental Protection Agency (Cal/EPA) to study policies that would shift some costs of biomass energy production away from the electric ratepayer, and onto the beneficiaries of the waste disposal services it provides. Cal/EPA was directed to report to the legislature on biomass cost-shifting measures by April 1997.

Cal/EPA had difficulty coming to grips with this political football. Two of the principal agencies under the Cal/EPA umbrella, the California Air Resources Board and the California Integrated Waste Management Board (CIWMB), had obvious interests in the outcome of the process. In addition, agencies outside Cal/EPA, such as the California Department of Forestry and Fire Prevention and the California Energy Commission, also have a strong interest in policies affecting biomass energy production. Rather than take the lead itself, Cal/EPA assigned the task to the Waste Board. CIWMB convened a series of public workshops, during which they solicited research and information about the public benefits of biomass energy production, and policy proposals to support continued biomass energy production. A great deal of public input was received, which the agency tried to distill into a report to the legislature within a very tight time frame. At some point a decision seemed to have been made that any information that caused interagency disagreements would be removed from the report. The result was a watered-down report that provided the legislature with no basis for enacting the kinds of cost-shifting policies for biomass envisioned in AB 1890.

The legislature made one more attempt to develop the background necessary for the developing biomass support policies in California. In 1998, AB 2273 was passed and signed into law. AB 2273 directs Cal/EPA to report annually to the legislature on progress in developing biomass cost-shifting policies in the state. CIWMB was assigned the lead role in developing the first report under this legislation. Although a report was prepared in early 1999 and sent to the Cal/EPA Board for approval, it was never released and sent to the legislature.

Despite the cloud of uncertainty over the future viability of biomass energy production in California, the state's biomass energy industry has operated with relatively stability during the latter half of the 1990s. Following the shutdowns of 1994-1996, 27 biomass facilities, representing 540 MW of generating capacity, remained in operation. Twenty operated under intact SO#4s. The other seven had special circumstances, such as a captive fuel supply or an ability to earn retail-offset for most or all of their electricity output, that allowed them to continue operating. The fixed-price periods in the SO#4 PPAs came to an end at the end of the 1990s, but the renewables transition fund created by AB 1890 offered biomass generators a supplement of 1.5¢/kWh for facilities that did not receive SO#4 fixed-scheduled prices for their sales of electricity.

The operating biomass energy generating capacity in California actually increased slightly at the end of the 1990s, to almost 600 MW. This was mainly because two 25-MW facilities that had accepted contract buyouts and shut down operations in 1994 had special provisions in their buyouts that provided for restarting the facilities at the end of their fixed-price periods. These facilities resumed operations in 1998 and 1999, respectively. Biomass fuel use increased by 15% over its low point following the 1994-1996 shutdowns, but was still more than 30% lower than the peak level achieved during the early part of the decade. Table 4.1 shows a list of all the biomass energy generation facilities that have operated in California since 1980. Figure 4.4 shows a current map of the California biomass energy facilities, keyed to the list of facilities in Table 4.1.

Figure 4.4: California Power Plants, 2000

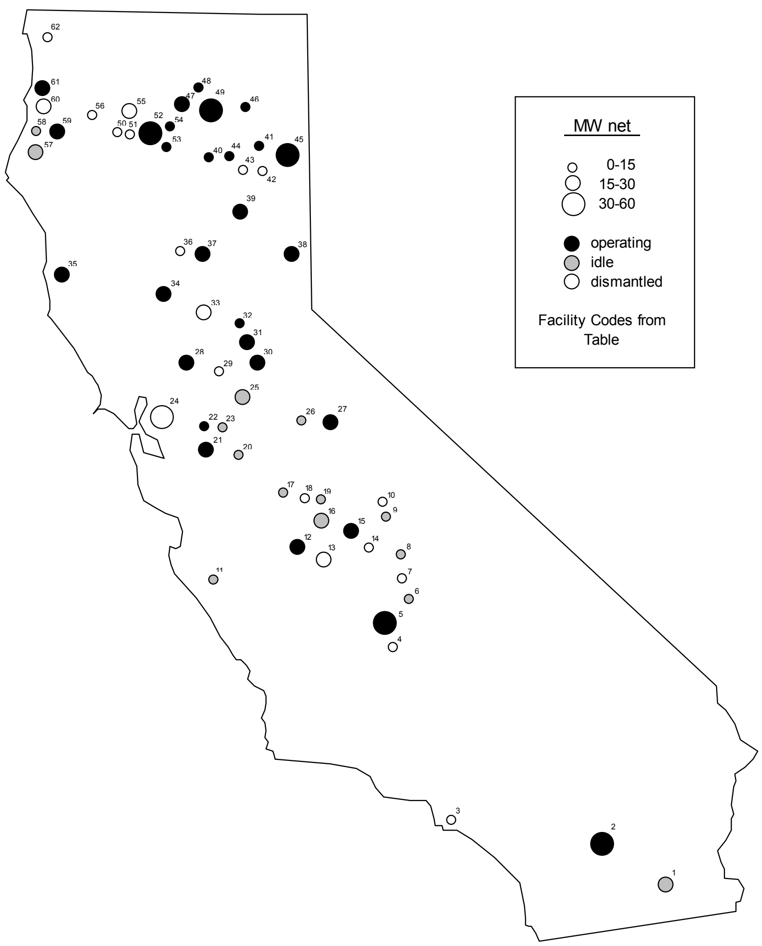


TABLE 4.1:CALIFORNIA BIOMASS POWER PLANTS, 1980-2000

	Project	County	Net MW	mBDT/y	Cogen	Own Fuel	Boiler Type	Status	Utility	PPA	Start Up	Shut Down	Re-Start
1	Western Power	Imperial	15.0	122			grate	Idle	SCE	SO #4 bo	1990	1996	
2	Colmac Energy	Riverside	47.0	330			cfb	Operating	SCE	SO #4	1992		
3	Proctor & Gamble	Los Angeles	13.5	98	x		grate	Dismantled	SCE	Pre SO	1985	1988	
4	Apex Orchard	Kern	5.5	48	x		grate	Dismantled	PG&E	Pre SO	1983	1988	
5	Thermo Ecotek Delano	Tulare	48.0	375			bfb	Operating	SCE	SO #4	1991		
6	Sierra Forest Products	Tulare	9.3	75	x	x	grate	Idle	SCE	SO #4 bo	1986	1994	
7	Lindsay Olive	Tulare	2.2	20	x	x	grate	Dismantled	SCE		1980	1993	
8	Dinuba Energy	Tulare	11.5	97	x	x	bfb	Idle	PG&E	SO #4 bo	1986	1995	
9	Auberry	Fresno	7.5	70	x	x	bfb	Idle	PG&E	SO #4 bo	1986	1994	
10	North Fork	Madera	8.0	68	x	x	bfb	Dismantled	PG&E	SO #4 bo	1988	1994	
11	Soledad Energy	Monterey	13.5	98			bfb	Idle	PG&E	SO #4 bo	1990	1994	
12	Thermo Ecotek Mendota	Fresno	25.0	185			cfb	Operating	PG&E	SO #4	1990		
13	Agrico Cogen	Fresno	25.0	198	x		grate	Conv. to gas	PG&E	SO #2	1990	1991	
14	Sanger (biomass → feed)	Fresno	0.0	50	x		-	Dismantled	NA	NA	1991	1991	
15	Rio Bravo Fresno	Fresno	25.0	180			cfb	Operating	PG&E	SO #4	1989	1994	1998
16	SJVEP--Madera	Madera	25.0	182			bfb	Idle	PG&E	SO #4 bo	1990	1995	
17	SJVEP--El Nido	Merced	10.2	88			bfb	Idle	PG&E	SO #4 bo	1989	1995	
18	SJVEP--Chowchilla I	Madera	9.9	99			grate	Dismantled	PG&E	SO #4 bo	1988	1995	
19	SJVEP--Chowchilla II	Madera	10.8	90			bfb	Idle	PG&E	SO #4 bo	1990	1995	
20	Redwood Food Pkg	Stanislaus	4.5	36	x	x	grate	Idle	PG&E	SO #1	1980	1985	
21	Tracy Biomass	San Joaquin	19.5	150			grate	Operating	PG&E	SO #4	1990		
22	Diamond Walnut	San Joaquin	4.5	35	x	x	grate	Operating	PG&E	Pre SO	1981		
23	California Cedar Products	San Joaquin	0.8	11	x	x	grate	Idle	PG&E	SO #1	1984	1991	
24	Gaylord Antioch	Contra Costa	30.0	225	x		grate	Conv. to gas	PG&E	Pre SO	1983	1990	
25	Jackson Valley, Ione	Amador	18.0	140				Idle	PG&E	negotiated	1998	1999	
26	Fiberboard, Standard	Tuolumne	3.0	27	x	x	grate	Idle	PG&E	Pre SO	1983	1996	
27	Chinese Station	Tuolumne	22.0	174			bfb	Operating	PG&E	SO #4	1987		
28	Thermo Ecotek Woodland	Yolo	25.0	200			cfb	Operating	PG&E	SO #4	1990		
29	Blue Diamond Growers	Sacramento	9.5	68	x	x	grate	Dismantled	PG&E	Pre SO	1982	1996	
30	Wheelabrator Martell	Amador	18.0	135	x	x	grate	Operating	Industrial Cust.		1987		
31	Rio Bravo Rocklin	Placer	25.0	180			cfb	Operating	PG&E	SO #4	1990	1994	1999
32	Sierra Pacific Lincoln	Placer	8.0	70	x	x	grate	Operating	PG&E	SO #4	1985		
33	EF Feather River	Yuba	16.5	150			cfb	Dismantled	PG&E	SO #4 bo	1987	1993	
34	Wadham Energy	Colusa	26.5	209			cfb	Operating	PG&E	SO #4	1989		
35	Georgia Pacific	Mendocino	15.0	119	x	x	grate	Operating	PG&E	SO #1	1987		
36	Koppers	Butte	5.5	110	x	x	grate	Dismantled	PG&E	SO #2	1984	1994	
37	Ogden Pacific Oroville	Butte	18.0	142			grate	Operating	PG&E	SO #4	1986		
38	Sierra Pac. Loyalton	Sierra	17.0	134	x	x	grate	Operating	Sierra Pacific		1990		
39	Sierra Pacific Quincy	Plumas	25.0	200	x	x	grate	Operating	PG&E	SO #4	1987		
40	Collins Pine	Plumas	12.0	90	x	x	grate	Operating	PG&E	SO #2	1986		
41	Sierra Pac. Susanville	Lassen	13.0	105	x	x	grate	Operating	PG&E	SO #4	1986		
42	Lassen College	Lassen	1.5	12	x		grate	Dismantled	PG&E	SO #1	1985	1987	
43	Jeld Wen Industries	Lassen	2.5	20	x	x	grate	Conv. to gas	PG&E	Pre SO	1984	1992	
44	Ogden Westwood	Lassen	11.4	90			grate	Operating	PG&E	SO #4	1985		
45	Honey Lake Power	Lassen	30.0	225			grate	Operating	PG&E	SO #4	1989		
46	Big Valley Lumber	Lassen	7.5	59	x	x	grate	Operating	PG&E	Pre SO	1983		
47	Sierra Pacific Burney	Shasta	17.0	145	x	x	grate	Operating	PG&E	SO #4	1987		
48	Ogden Burney	Shasta	10.0	77			grate	Operating	PG&E	SO #4	1985		
49	Burney Forest Products	Shasta	31.0	245	x	x	grate	Operating	PG&E	SO #4	1990		
50	Roseburg Lumber	Shasta	4.0	32	x	x	grate	Dismantled	PG&E	Pre SO	1980	1992	
51	Paul Bunyan	Shasta	3.0	24	x	x	grate	Dismantled	PG&E	Pre SO	1980	1992	

The year 1999 saw a renewal of interest in PPA buyouts. One small facility, which was already operating past its fixed-price period, accepted a buyout agreement for its remaining capacity obligation and shut down. One of the state's largest facilities accepted a buyout of its contract, and remains in operation as a merchant power facility, although its future viability is in doubt. Other possible buyouts were in various stages of discussion, and future shutdowns are possible as the new century begins. The cap on the renewable transition supplement paid to biomass generators decreased to 1.0¢/kWh on January 1, 2000, and more than 100 MW of capacity will see their fixed-schedule energy provisions expire during 2000. No biomass support measures have yet been enacted. The industry's future remains very much in doubt.

Characteristics of California's Biomass Power Plants

Gregory Morris of the Green Power Institute has developed and maintained an extensive database on the California biomass energy industry (Morris 1997), which has been brought up to date as part of this project. The California biomass energy database contains information about every solid fuel biomass energy generating facility that has operated in California since 1980. The database includes information about biomass fuel use and price on an annual basis, and annual electricity production, for the 20-year period covered, 1980-1999, as well as projections for the current year (2000). This database is the source of much the data used in the environmental and economic analyses in this report.

Sixty-two biomass energy generating facilities have operated in California during the past 15 years. Twenty-nine still operate. Eighteen have been dismantled or otherwise modified to render them no longer available for service as biomass energy facilities. Most of the remaining 15 facilities are currently idle and available for future operations. They are located throughout the state, as shown in Figure 4.4. Half obtain at least some of their fuel from captive sources, although only a few obtain all their fuel from captive sources. Thus, most have participated in the state's biomass fuels marketplace. California biomass facilities range from 1–50 MW, with annual fuel requirements of 10,000–750,000 tons/year.

All biomass energy generation facilities in California employ conventional steam-turbine technology for converting biomass fuels to electricity. This technology has been in use for almost 100 years, and has been used extensively with a wide variety of fuels, including biomass and fossil fuels. Nevertheless, the technology continues to evolve, and has shown significant improvement as the modern biomass energy industry in California has developed. Much of the development since 1980 has been in the area of environmental performance, which includes improvements in combustion technology and in emissions-control technology.

Most of California's biomass power plants employ conventional biomass combustion technology with fixed or traveling grate furnaces. Seventeen of the facilities were built with fluidized-bed boilers, including bubbling bed and circulating bed configurations. Fluidized-bed boilers provide for lower emissions and higher efficiency than conventional boilers, but have higher capital and operating costs. The major deployment of fluidized-bed biomass boilers has contributed valuable learning experience to the continuing technological refinement and commercial development of this promising technology.

The industry is poised to continue to contribute to technological innovation in the biomass energy arena as the twenty-first century begins. The newest biomass generating facility in the state, taking advantage of the IRS Section 29 gasification tax credit, employs a close-coupled gasifier as part of its combustion system, achieving high efficiency and low emissions. Several biomass facilities are considering the development of associated ethanol production operations as an enhancement to the overall energy production enterprise. It is hoped that synergies between the electricity production enterprise and the ethanol production enterprise, such as shared biomass procurement and handling facilities, and segregation of the resource into higher and lower valued outlets, will provide benefits to both. The California biomass energy industry can contribute to future biomass technology innovation only if it continues to be viable in the near-term.

Fuel Use and Alternative Disposal Options for Biomass Residues in California

The biomass energy industry in California can be thought of as much as a solid waste disposal service provider as an electricity generating enterprise. It provides for the disposal of 6.4 million tons/year of the state's solid wastes. The biomass residues used as fuel come from a variety of sources, and would be subject to a variety of alternative fates, such as open burning or landfill burial, if the biomass industry were not a disposal option. The major categories of biomass fuels used in California include:

- Wood processing residues
- In-forest residues

- Agricultural residues
- Urban wood residues

Most biomass generating facilities in California were built with an expectation of using either wood processing residues or agriculture residues as their major fuel source. The facilities designed to burn primarily agricultural residues are concentrated in the Central Valley. Those designed to burn primarily residues from the forest products industry are concentrated in the northern and eastern mountain regions. Three biomass facilities were designed to burn primarily urban wood waste. These were located close to the Los Angeles and San Francisco Bay Areas. Urban wood waste fuels, which were largely ignored during the industry's development, have become far more important than anyone originally anticipated. They are second only to sawmill residues in terms of their contribution to the California biomass fuels market.

Several California biomass facilities burn supplemental fuels in addition to solid biomass residues. Biomass energy facilities that are qualifying facilities (QFs) are allowed to obtain as much as 25% of their input heat from conventional fossil fuels. In addition, they can burn unlimited quantities of other renewable fuels or approved waste materials, such as petroleum coke and old tires. Landfill gas,[4] tires, and petroleum coke are the major supplemental fuels used by the state's biomass generators. One facility uses geothermal heat to preheat boiler water.

Wood Processing Residues

Wood processing residues are the waste materials produced during the processing and conversion of lumber into wood products. Those residues are the most important biomass fuel source in California, consistently accounting for more than one-third of the total biomass fuel supply used. Almost half the biomass content of a typical sawlog becomes residue at a primary sawmill. A variety of secondary forestry industries have been developed to use some of this material. Active markets for wood processing residues include pulp chips, wood fiber for fiberboard and composites, animal bedding, and garden products such as decorative bark. Sawmills are used to segregating their residues into the highest-value markets available, but a substantial quantity of the residues, typically 15%-20% of the total biomass in a sawlog, has no useful application and must be disposed of. Wood-processing residues are produced in a variety of forms, including:

- Bark
- Round-offs
- End cuts
- Trimmings
- Sawdust
- Shavings
- Reject lumber

The traditional method of disposing of sawmill residues in California before the biomass energy industry was developed was incineration in teepee burners, a technology that produces large quantities of smoke and air pollution. Beginning in the early 1970s, air pollution control efforts applied increasing pressure on sawmills to close down their teepee burners, leading them to look for new disposal alternatives. This was one important factor that led to the early development of the biomass industry in California. Virtually all the readily available wood processing residues generated that have no higher valued application are now used as power-plant fuel.

[4] California has 30 power generation installations powered exclusively by landfill gas. This report is focused on the solid fuels biomass power industry, and does not cover the landfill gas facilities.

Teepee burners are no longer used to dispose of wood processing residues in California. The only readily available option for disposing of these materials, if fuel use were not a possibility, would be landfill burial – a highly undesirable alternative. Waste wood has a slower decay rate than other forms of biomass in the landfill environment, and thus is slower to stabilize. Moreover, state solid waste policy is strongly oriented to reducing the amount of material being buried in landfills, and introducing a sizable new waste stream would make compliance with recycling regulations almost impossible.

If there were no biomass energy industry in California today, some sawmill residues currently used for fuel would be used for energy production in sawmill kiln burners, an old disposal option for some of a sawmill's residues. This application would probably use one-third or more of the residues currently used for power production. A small quantity would be composted and/or spread; the rest would be landfilled.

Wood processing residues are the cheapest of the four categories of biomass fuels to produce and deliver to the power plants. They form the backbone of the state's biomass fuel supply, and would probably be the last type of fuel to exit the system if the demand for biomass fuels state declined. The major factor that determines the quantity of mill residues used as fuel in California is the level of activity in the forest products industry. Economic factors and environmental restrictions on timber supplies have led many sawmills to shut down. This has led to a decline in the amount of wood processing residues used as power plant fuels, which began during the early 1990s.

In-Forest Residues

In-forest biomass residues include two major categories: residues generated in the forest when timber is harvested for wood products, generally called slash, and material naturally occurring in forests whose removal would provide environmental benefits to the remaining forest. Harvesting residues include the tops and limbs of harvested trees, bark when debarking takes place in the forest, and cull logs[5] that are cut and removed during harvesting operations. The cheapest way to manage this material is to leave it in the forest as it is generated, but that is also the worst management practice from a forestry perspective, as leaving harvesting residues in the field retards regrowth of the forest and represents a substantial fire hazard. Virtually all timber harvesting contracts in California require loggers to manage the slash they generate. Slash that is generated close enough to an operating biomass energy plant can be collected and converted to fuel. The alternative is to collect the slash and burn it in piles. Open burning leads to high levels of emissions of smoke, particulates, and other air pollutants.

The other category of in-forest residue is overstocked material in vast areas of California's forests. Poor forestry practices and aggressive fire-fighting efforts during most of the past century have resulted in vast areas of the state's forests becoming overstocked with biomass. This material represents an enhanced risk of destructive wildfires, and generally degrades the functioning of the forest ecosystem. Overstocked forests benefit greatly from thinning operations. The quantity of in-forest biomass whose removal would benefit California's forests is far greater than the total amount of biomass fuel demand in the state. However, this fuel source is generally more expensive to produce than other types of biomass fuels, so less is used.

Two basic alternatives can be used to reduce the biomass overloading in standing forests: prescribed burning and mechanical thinning. The primary goal of reducing fire risks in standing forests is to protect mature trees. Most of the tonnage of forest overgrowth biomass is material on and near the forest floor, called ground fuel. Periodic fires in undisturbed California forests tended to be primarily ground fires, and control the buildup of these materials. When ground fuels are left uncontrolled for prolonged periods, such as in areas where fires have been excluded for 75 years or more, some of the undergrowth

[5]Cull logs are trees that are diseased, damaged, misshapen, or otherwise unsuitable for use in producing commercial wood products.

begins to grow into taller poles, which become "ladder fuels." Ladder fuels provide a mechanism to transfer ground fires to the crowns of mature trees in the forest, thus greatly increasing the damage caused by the fires, in the worst cases turning benign ground fires into out-of-control, destructive wildfires. Traditional commercial harvesting operations do not affect the fuel overloading problem in the forest, because neither ground nor ladder fuels are removed. In fact, if slash is left untreated, the fire risk can be increased. Mechanical thinning and prescribed burning remove ladder and ground-based fuels.

Forestry officials would like to see large areas of California's forests thinned. An official of the U.S. Forest Service, which manages approximately one-half the state's forest land, has asserted that at least 250,000 acres per year of the land under their jurisdiction needs to be thinned to fully realize the desirable fire suppression, forest health, and watershed improvement benefits (Morris 1998a). During the peak of the California biomass fuels market in the early 1990s only about 60,000 acres per year were being thinned statewide for fuel production. With the decline in biomass fuels demand that occurred in the middle of the decade, the level of thinning for fuels production has been cut by more than half.

The alternative to biomass fuels production for reducing overstocking in the state's forests is prescribed burning. However, environmental and safety concerns may limit the amount of prescribed burning that will be allowed in California. Prescription burning produces more pollution per ton of material consumed than open burning of biomass in piles (EPA 1995). In addition, prescribed burning in densely overstocked forest stands entails a significant risk of residual stand damage and may initiate of offsite, uncontrolled wildfires. The recent massive wildfire in Los Alamos, New Mexico, has already become a notorious example of a prescribed burn running amok, but northern California has experienced this phenomenon on a smaller scale repeatedly during the past decade. Mechanical thinning and residue removal before prescription burning reduces the pollution and risk factors associated with the treatment, and in some cases can eliminate the need to burn. Mechanical thinning, however, is expensive, and rarely performed in the absence of fuel applications for the thinned material.

Agricultural Residues

Agriculture is a multibillion-dollar enterprise in California, producing large quantities of biomass residues in the process. Approximately one-third of California's biomass energy plants were built in the state's agricultural regions in order to use these residues as fuel. Many receive emissions offsets for pollutants that are avoided when biomass residues that would otherwise be open burned are used for energy production. Agricultural fuels provide about 20% of the state's biomass fuel supply. Agricultural residues come in a wide variety of forms, some which are unsuitable for use as power plant fuel. Agricultural residues suitable for fuel use in solid-fuel biomass energy plants include materials in the following categories:

- Food processing residues such as pits, shells, and hulls
- Orchard and vineyard removals
- Orchard and vineyard prunings
- Field straws and stalks

Food processing residues are generated in concentrated quantities and require some form of disposal. Like wood products manufacturers, food processors have worked diligently to develop high-valued uses for these materials, such as in feed products. Nevertheless, a surplus of food processing residues is available for use as biomass fuel. In the absence of fuel markets, these materials would otherwise be buried in a landfill or open burned. Some wastes that have been used as fuels in California, such as nut hulls, shells, pits, and rice hulls, present special combustion problems that limit their application to facilities able to deal with these materials. Several pioneering biomass generating facilities were built at food processing facilities specifically to dispose of the processing residues. Although some experienced operating problems when first starting up, most were able to adapt and adjust their equipment to handle the specific fuels.

California's agriculture includes extensive plantings of orchards and vineyards, permanent woody crops that require annual pruning operations and produce large quantities of residues. Conventional agricultural practice for the disposal of these prunings is to pull them to the sides of the rows, where they are piled and burned. It has long been recognized that agricultural burning is a major contributor to the air pollution problems in California's major agricultural regions. During the early development of the biomass energy industry there was a great deal of interest in using orchard and vineyard prunings as fuels. Combustion of this material in a power plant greatly reduces the resulting emissions of smoke and air pollutants compared with open burning. In addition to the environmental benefits anticipated, many farmers were under the impression that fuel sales would offset the cost of pruning, and even create a new profit center for their operations.

Orchard and vineyard prunings are more expensive and difficult to use as fuels than was originally anticipated. This is a consequence of two factors. First, the density of the resource (tons per acre) is less than originally projected. The result of this miscalculation is that more area needs to be covered to produce a given amount of fuel, which results in concomitant increase in fuel production cost. Second, compared with other sources of biomass boiler fuels, prunings are very stick-like, which makes them more difficult to process into fuel form and creates a special hazard for fuel handling and delivery equipment at the power plant. These considerations have limited the amount of fuel produced from orchard prunings in California. It is estimated that less than 7.5% of the state's agricultural prunings are being converted to fuel in the current market environment. The remainder continues to be open burned.

In contrast to the experience with prunings, orchard and vineyard removals constitute very desirable source of biomass fuel. Orchards and vineyards are cleared periodically for purposes of replanting, and in response to changing land use decisions. Orchard clearing, in particular, provides a high density of material (tons per acre) that can be processed into conventional whole tree chips. In addition, this material is generally felled in the mid to late summer from plantations that have not been irrigated, the wood is often very dry compared with other sources of recently cut biomass fuels. Fuels derived from orchard clearings, and to a more limited extent from vineyard clearings, are the major agricultural residue fuels used in California.

California agriculture also produces large quantities of field residues in the forms of straws and stalks that are disposed of either by open burning, or by plowing under in the fields. These residues can be collected and processed into power plant fuels. Straw and stalk-based fuels tend to be expensive to produce, and their low bulk density (lb/ft^3) presents materials handling problems and combustion difficulties. As a result, very little of this material contributes to the fuel supply, even though these materials qualify as agricultural offset fuels.

Most agricultural residues used as fuels in California are woody residues derived from extensive orchard crops. Whole-tree chips produced from orchard removals constitute a particularly successful source of biomass fuel. Even with the present level of agricultural biomass fuel use, an enormous amount of agricultural residues suitable for use as power plant fuels continues to be open burned. The alternative fate for most agricultural residues used for fuel is open burning, although a small percentage of these materials would likely be landfilled or plowed under in the absence of fuel applications.

Urban Wood Residues

Fifteen to twenty percent of the material traditionally disposed in municipal landfills is clean, separable waste wood. This material comes from a variety of sources, including:

- Waste wood from construction contractors
- Old and damaged pallets
- Waste wood from land clearing
- Waste wood from public and private tree trimmers and landscapers
- Waste wood from industrial manufacturers, including packing materials and trimmings

Urban wood residues are brought to landfills in a variety of forms, including loads of chipped wood and brush from public and private tree trimmers and land clearers, debris boxes from manufacturers of wood products and construction contractors, and mixed loads of yard debris. Some amount of demolition wood waste is also used as a biomass fuel, although many facilities have permit restrictions that prohibit the use of painted wood and/or treated wood because of emissions concerns. Transfer station and landfill operators can segregate loads containing fuel-usable materials as they enter the gate, and process the material to produce a high-quality fuel product. Urban wood residues contribute much more to California's biomass fuels mix than anyone anticipated during the early development of the industry.

Landfill-diverted waste wood supplied about 1.5 million tons of fuel annually to the biomass energy industry during the 1990s, hitting a peak of 1.9 million tons in 1993. As the overall biomass fuels market declined through the decade, the percentage of landfill-diverted fuels in the state's biomass fuel mix has increased, from approximately 20% at the beginning of the decade, to 30% today. Landfill-diverted waste wood is the second cheapest source of biomass fuel to produce after sawmill residues, in large part because of the pressure to divert wastes away from landfill disposal.

The traditional disposal option for urban wood waste is burial in landfills. However, the alternative disposal options that might be available for this material in the future, should the fuels market disappear, are more complicated to project. California's solid waste diversion law, AB 939, mandates that by the end of 2000 all counties must achieve a diversion rate of 50% of their total solid waste, compared to their performance during 1990. An intermediate target of 25% diversion by 1995 was met statewide, but compliance with the year 2000 standards will be significantly more difficult to achieve. Peak urban biomass fuel use of 1.9 million tons/year represents 6.6% of the amount of solid waste that must be diverted statewide by the end of 2000.

Solid waste managers are under pressure to develop diversion applications of all kinds. The alternatives, however, are limited, and most of the obvious markets that can accept waste wood, such as spreading as mulch or composting, are already being flooded with material. Most of the urban biomass fuels would otherwise probably be landfilled; some would be spread as mulch or composted.

The California Biomass Fuels Market

During the early development of the biomass energy industry in California, wood processing and agricultural residues provided virtually all the fuel used by the various biomass power producers. As the industry grew the use of these sources of fuel grew in step, and two new sources of fuel were introduced: in-forest residues and urban wood residues. Figure 4.5 shows the time course of the use of the four categories of biomass fuels as a function of fuel type. Wood processing residues have continued to be the primary source of supply for the biomass energy industry throughout the period covered by this study. The use of wood processing residues as fuel increased rapidly during the 1980s, peaking in 1990 at more than 5.5 million tons/year. At that point all but the most remote wood processing residues were being used as biomass fuels.

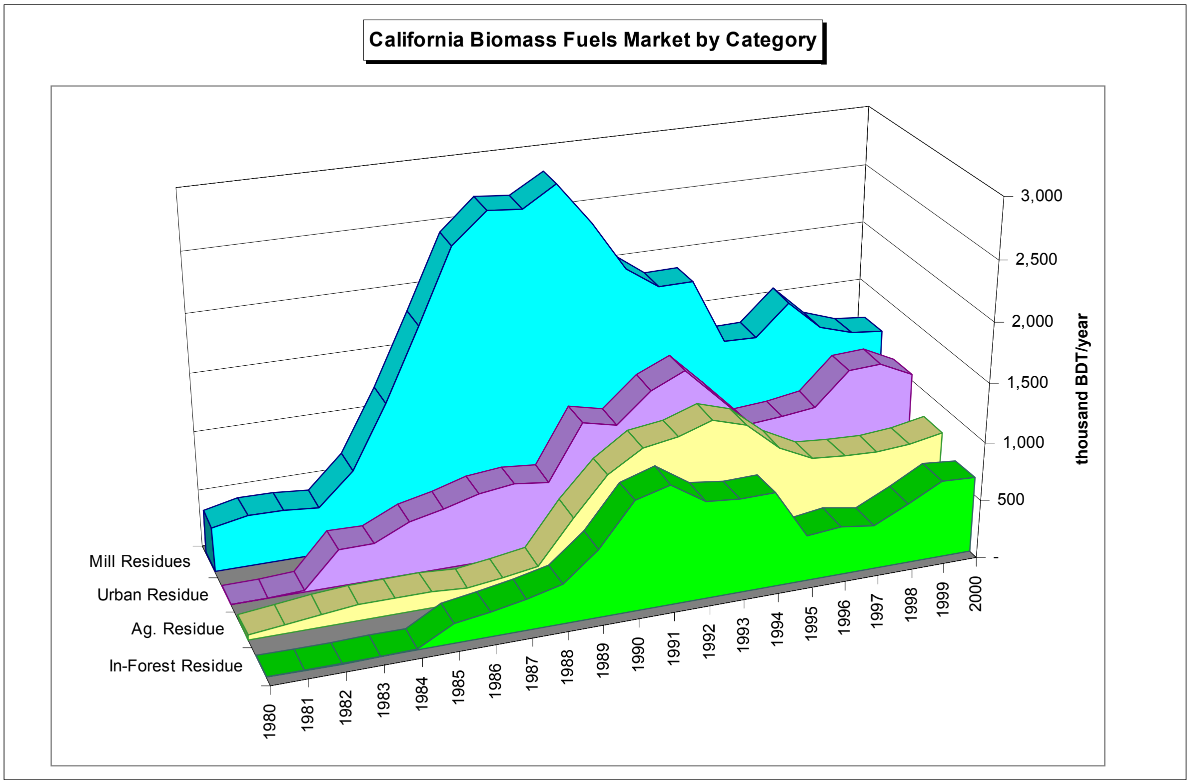


Figure 4.5

Although the demand for biomass fuels remained relatively stable during the early 1990s, the use of mill residues dropped dramatically during this period. This was a result of the fact that sawmilling activity in the state declined in response to poor economic conditions and increasing environmental restrictions on the supply of round wood. At the same time supplies of the other types of biomass fuels became more available as high biomass fuel prices and long-term fuel supply contracts required by the financial institutions that funded the power plants stimulated a variety of new ventures in the fuel supply business. As the lowest-cost-to-produce fuel source, mill residues are used to the full extent they are available. The state's biomass energy industry would have to shrink to less than half its current size before significant quantities of mill residues would start to be disposed of using alternative disposal options.

The other category of biomass fuels that has been in use since the beginning of the development of the biomass energy industry is agricultural residue fuels. The first agricultural fuels to be used were food processing residues such as nut hulls and pits. Several pioneering biomass energy facilities were built at food processing facilities to provide for the disposal of these materials. Expansion of the use of agricultural fuels has been more gradual than many industry observers originally predicted, because converting of orchard and vineyard prunings to fuels was more difficult and expensive than originally projected. Agricultural fuel use increased significantly between 1988 and 1990, as the statewide biomass fuel crisis hit, and many new facilities entered operation with permit requirements to burn agricultural wastes to offset their air pollutant emissions. With the closure of many agricultural fuels-based facilities during the mid-1990s, agricultural residue fuel use declined by about 33% from its peak in the early part of the decade.

Urban waste wood began to contribute to the state's biomass fuel mix in 1983, when Gaylord Paper Corp. started up its pioneering facility in the San Francisco Bay area. This facility was designed to burn primarily urban waste wood fuel, and was a very successful venture. In 1985 a second facility designed to burn urban wood fuel, Procter & Gamble, began operations in the Long Beach (Los Angeles) area. These two facilities, located in the two largest metropolitan areas, stimulated the development of a market for producing fuel from material that was traditionally buried in landfills.

As the technical viability of using urban waste wood fuels was proven, biomass energy facilities designed to burn primarily sawmill and agricultural residue fuels began purchasing fuels derived from urban waste wood, and the use of urban biomass fuels in California increased gradually during the mid-1980s. When the statewide biomass fuel crisis hit at the end of the decade, urban biomass fuel use doubled, reaching approximately 1.5 million tons/year in 1990. This fuel source continued to grow over the next several years, as statewide fuel demand remained stable and the availability of wood processing residues decreased. Urban biomass fuel use peaked at almost 1.9 million tons in 1993. Urban biomass fuel use contracted to below 1.2 million tons/year as overall biomass fuel demand declined with the shutdowns of the middle of the decade, then began to pick up again as the 1990s came to a close. With increasing pressure to divert material from landfill disposal to comply with AB 939, urban biomass fuel use currently exceeds 1.5 million tons/year.

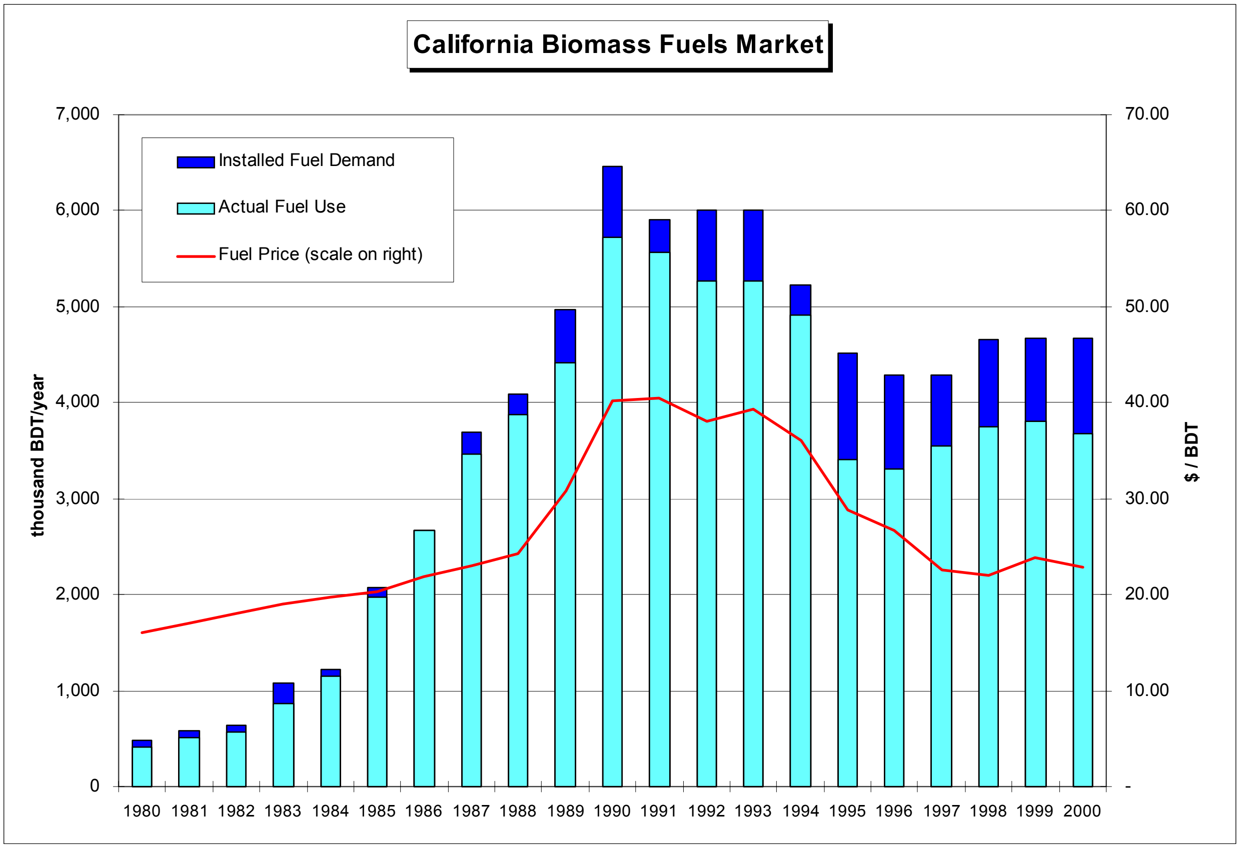
In-forest residues are the most expensive of the four types of biomass fuel sources used in California. Significant in-forest fuel production did not begin until 1985, and grew gradually until the end of the decade, when the statewide fuel crisis forced fuel prices above $40/bdt. In-forest biomass fuel use peaked in 1990-1991 at about 1.8 million tons/year, then began to fall as the market reached equilibrium, sawmilling activity recovered slightly, and cheaper urban and agricultural fuels out competed in-forest fuels. When the buyouts and closures hit the biomass energy industry in 1994-1995, in-forest biomass fuel use took the greatest hit, dropping to less than 700,000 tons/year in 1997. Since then in-forest residue fuel use has rebounded to more than 1 million tons/year.

Biomass Fuel Market Price Trends

Before the development of the modern biomass energy industry in California most agricultural and wood-processing residues, as well as a significant quantity of the forest harvesting residues, were being open burned, while urban wood residues were being buried in landfills. In addition, the amount of overstocking of fuel in the state's forests was increasing relentlessly, a process that has spanned the entire twentieth century. These disposal alternatives have economic costs as well as adverse environmental consequences. The early development of the state's biomass energy industry was spurred as much by sawmills and food processors looking for improved disposal options for their residues, as by the incentives provided by the energy sector.

During the early development of the biomass fuels market in California, a surplus of residue material was available for conversion to fuel, and fuel prices were based primarily on the cost of processing the residues and transporting them to the power plants. During the early 1980s, biomass fuel prices were stable, about $15-20 per bdt. Some sawmill residues were sold to nearby generating facilities for less than $10/bdt. Figure 4.6 shows the average price of biomass fuels as a function of time.

Figure 4.6



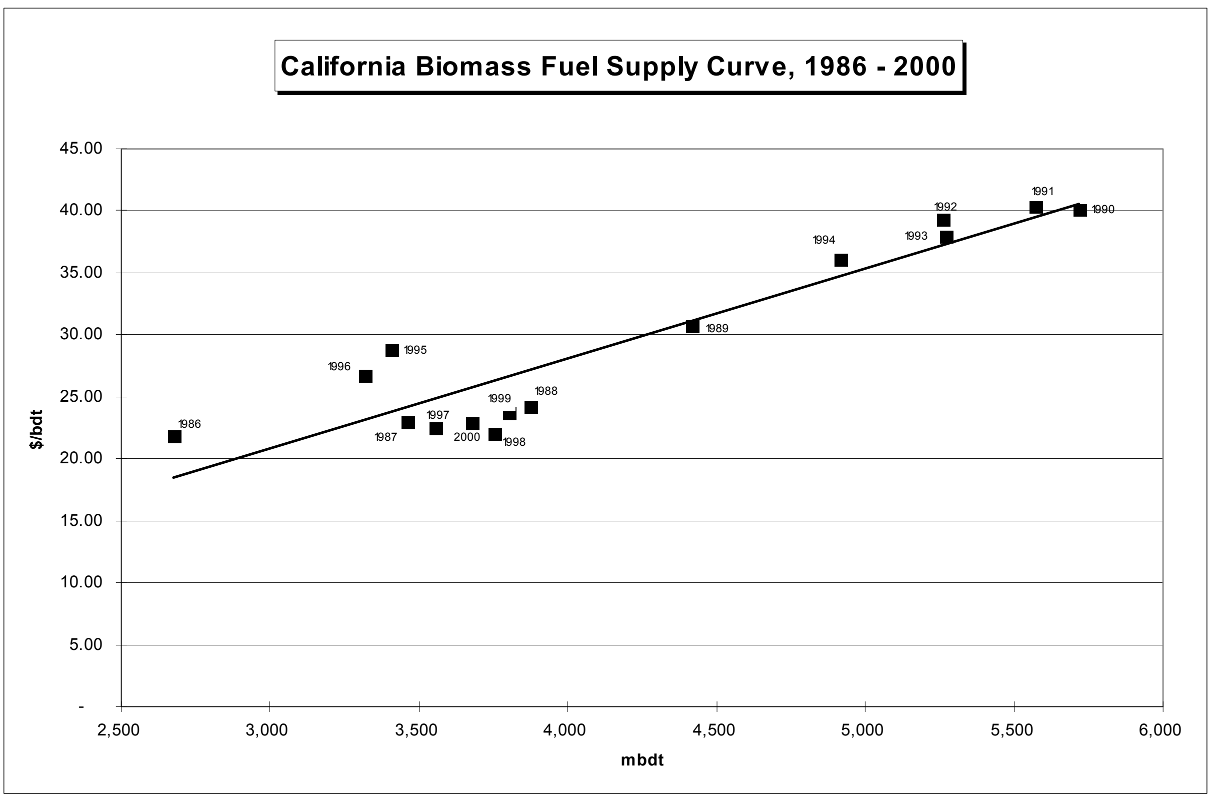
As biomass fuel demand increased during the mid to late 1980s, the average statewide price of biomass fuels began to climb upward, reaching an average value of almost $25/bdt by 1988. From 1980 to 1988, fuel demand grew at a greater rate than the rate of increase in fuel prices. The inflation-corrected price of biomass fuel was virtually unchanged during this period. From that point forward, however, fuel demand reached a critical level, and prices shot up, reaching more than $40/bdt during the early 1990s, with spot prices reportedly tipping $60/bdt. The industry appeared to be in a full-blown fuel crisis, which was precipitated by the extremely rapid increase in generating capacity, and the requirements for long-term fuel supply contracts imposed by the banks on the power plants as a condition of funding.

By 1988, statewide biomass fuel demand had grown to the point that it exceeded the capacity to provide biomass fuels. The cheapest source of biomass fuels, mill residues, was completely committed to the fuels market, and additional mill residues were no longer available to satisfy new fuel demand. New sources of biomass fuels were required, and significant investments had to be made to develop the new fuel supplies. In general, the new supplies of fuel were more expensive than the fuel sources that had already been developed. These were all factors in the rapid increase in biomass fuels prices that occurred between 1988 and 1990, during which statewide average biomass fuel prices increased by approximately 60%.

By the end of 1990 the demand for biomass fuels stabilized, as did the price, which averaged about $40/bdt. The fuel-supply infrastructure had a chance to catch up with the demand, and a great deal of experience was accumulating with respect to the technologies necessary to produce power plant fuels from new sources of biomass, such as urban wood residues and various types of agricultural and in-forest residues. Fuel prices might have decreased somewhat during the early 1990s as a better balance was achieved between supply and demand, except that the supply of mill residues decreased significantly because of a cutback in lumber production (see Figure 4.5). Thus, the pressure for fuel price decreases due to an improved supply-demand balance was countered by the loss from the market of a fraction of the wood processing residues. The loss of wood processing residues had to be made up for by sources of supply that were more expensive to produce.

Beginning in 1994, the regulated California electric utility companies, in response to the deregulation process at the CPUC, initiated a series of buyout negotiations with many biomass generating facilities. Owners of approximately 200 MW of capacity accepted buyouts during 1994 and 1995, shutting down 25% of the state's operating capacity, and decreasing the demand for biomass fuels by more than one-third. Supply and demand were again out of balance, and fuel prices began a fall that brought them back to pre-1988 levels. Figure 4.7 shows a plot of the supply curve for biomass fuels in California. The data points represent the period 1986 to the present, showing, for each year in the range, the quantity of biomass fuel used and the average price.

Figure 4.7



The future for biomass fuel prices in California is difficult to predict. The renewable transition fund payments to biomass generators over the past 2 years have provided sufficient incentive for generators earning SRAC rates to increase their production during off-peak hours, compared with what they were doing before the transition funds were available. This, combined with the restart of two twenty-five MW facilities, has increased total fuel use, with a concomitant rise in fuel prices. As fixed-price periods expire for more facilities, and the renewable transition fund payments are ramped down and disappear by the end of 2001, this upturn in statewide fuel demand might very well be short lived. Power plant operating economics will ultimately determine the marginal price of fuel that producers will be willing to pay.

Summary of California Situation in 2000

The biomass energy industry in California reached its peak level of production during the early 1990s, and has since declined by more than one-third. This decline has a variety of causes, but the underlying reality is that biomass energy is expensive to produce compared with the lowest cost alternatives available on the grid. The high cost of biomass energy production, an inevitable result of the small facilities and the high cost of collecting and transporting low-density residue materials, is a considerable liability in a marketplace that is being deregulated and that increasingly emphasizes cost. As a result, unless biomass energy generators are compensated for the environmental benefits they provide, the viability of the enterprise is in serious doubt.

Loss of a significant fraction of the present level of biomass energy production in California would present serious social and environmental consequences. Almost 3 million tons/year of residues currently used as fuel would be added to the burden of material entering sanitary landfills, making compliance with AB 939 virtually impossible for many counties. Moreover, burying this material will burden the country with future greenhouse gas emissions that will not be avoidable when the Kyoto greenhouse gas emissions reductions must be achieved in 2012.

Disappearance of the industry would mean that more than 1.75 million tons of residues currently being used as fuels will return to open burning piles, where they will add measurably to the air pollution problems in agricultural and forested regions, many of which are already out of compliance with state and federal air-quality standards. Moreover, an additional 500,000 tons/year of residues will be allowed to accumulate in overstocked or otherwise unhealthy forests and watersheds. These residues will exacerbate the risks of destructive wildfires and ecosystem degradation that plague California's forests, and depress the productivity of many key watersheds.

The loss of the biomass energy industry would represent a loss of almost 3,000 rural employment positions, with serious negative impacts. Many rural communities would also lose their largest source of property taxes, and would suffer other economic multiplier effects as well. Energy diversity and security values would be lost.

The loss of the California biomass energy industry would exacerbate a number of important environmental problems, and leave affected rural regions with virtually irreplaceable losses of quality employment opportunities and tax base. In fact, increasing the capacity utilization of the infrastructure and encouraging the development of new biomass installations using ever-advancing technology, should be important goals of state and federal policy. The ancillary benefits of biomass energy production are worth far more than the above-market costs of operations. A modest level of compensation for these benefits will achieve a several-fold return in social and environmental benefits. The California experience with providing of biomass production credits 1.5¢/kWh demonstrates that this level of support can stabilize and increased the use of facilities. A higher level of support would be needed to encourage idle facilities to reopen, or the development of new biomass energy production capacity.

The California biomass energy industry provides a valuable, environmentally preferred waste disposal service for more than 6.4 million tons of the annual solid-waste stream. These services have been provided without compensation, as the electricity market was able to underwrite them fully. They will be lost to competitive electric market unless means are developed to compensate generators for their environmental services.

The total cost of support to maintain biomass energy production in California at its present level of activity is approximately $50 million/year, based on conditions that are expected at the beginning of 2002, the end of the transition period to full competition and the end of the RTF program. Most of the required amount could be provided by modifying the federal renewable energy tax credit, or extending public purpose funding for renewables in California beyond the end of the transition period. The remainder could be provided by targeted policy measures, such as appropriations of funds for wildfire risk reduction activities on state and federal forest lands, and for diverting agricultural prunings from open burning to energy production. Expanding the use of particular forms of residues through targeted policy measures will be well worth the cost in terms of the value of the benefits produced.

2002 Update on California Biomass Power Industry[6]

Natural gas prices in California, which had been stable throughout the 1990s, abruptly shot upwards during the winter of 2000. This was in no small part a result of pipeline capacity bottlenecks that were related more to business issues than to physical capacity constraints. Whatever the cause, this staggering increase in gas prices, combined with rapidly growing electricity demand fueled by the booming high tech industries in California, and a drought-caused decrease in hydroelectric production in the Pacific Northwest, led to electricity supply shortages in California.

Wholesale electricity prices, which had remained within a penny of three cents per kWh for more than 15 years, broke through the four-cent barrier in May of 2000. In June, they hit double digits. By August prices at the state power exchange were averaging more than 15¢/kWh. California was engulfed in a full-fledged energy crisis. The Governor resolved to hold the line on consumer electricity prices, and the utilities found their cash reserves evaporating rapidly.

Biomass power generators in the state responded quickly to what was a considerable opportunity. Each of the operating biomass facilities looked to expand its fuel purchasing, and pushed its facility to maximize output around the clock. All of the facilities that were eligible opted to convert to power exchange pricing in order to take advantage of the higher prices available there. Ten of the biomass facilities in California that had been shut down during the 1990s, representing 130 MW of generating capacity, began investigations to see whether they could profitably resume operations. The ten facilities, many of which are located near the state's Central Valley region, are shown in Table 4.2. The state support payments to the biomass generators were suspended because market prices exceed the target level. By the end of the year biomass fuel prices were on the rise, but few of the generators were complaining.

The complaints started promptly in December of 2000, when the utility companies stopped paying power producers for energy. Six months of unprecedented wholesale energy prices had mortally wounded the utility companies, and they were teetering on the verge of bankruptcy. To put the topping on the cake, prices at the power exchange suddenly shot up again in December, averaging more than 35¢/kWh during the month. They remained at that level into January 2001, when the power exchange itself was shut down. The electricity market in California was in chaos, and the state's investor-owned electric utility companies were crippled.

[6]Reference: Morris, G. (2002) "Biomass Energy Production in California," NREL Progress Report, Task Order No. KCL-0-30040-02, April

Table 4.2: Idle California Biomass Facilities that Began Re-Start Investigations in 2000

Auberry Energy, Auberry	7.5 MW	restart abandoned
Blue Lake Energy, Blue Lake	10.0 MW	restart abandoned
Capitol Power, Ione	18.0 MW	start up summer 2002
Chow II, Chowchilla	10.0 MW	restart abandoned
Dinuba Biomass, Dinuba	11.5 MW	started up in 2001
El Nido, Chowchilla	10.0 MW	restart abandoned
EPI Madera, Madera	25.0 MW	started up in 2001
Primary Power, Brawley	15.0 MW	started up in 2001
Sierra Forest Products, Terra Bella	9.5 MW	started up in 2001
Soledad Energy, Soledad	13.5 MW	started up in 2001

California's biomass power producers were faced with a mind-boggling irony. At the very time that they were earning unprecedented profits, they were facing insolvency. The supposed profits, of course, were only on paper. With their revenues suspended, fuel prices elevated, and the state demanding that they produce as much power as they could, their short-term cash positions were precarious. Many biomass operators talked openly of giving up and shutting down for good.

In spite of the troubles faced by the operating biomass facilities, the efforts to restart ten of the state's idled biomass facilities were proceeding full-speed ahead. Wholesale electricity prices had never been higher, actual operations for these facilities were months away, and it seemed reasonable to assume that something would be done to get the flow of money moving again. In fact, in many ways it appeared in the beginning of 2001 that the idled facilities that were trying to restart would enjoy a couple of distinct advantages over the operating facilities. They were not hobbled by having had to endure a prolonged period of operating without any revenues, and they were not saddled by old power purchase contracts that now were paying below-market prices.

Governor Gray Davis convened an emergency session of the state legislature in January 2001 to deal with the still burgeoning energy crisis. Many commentators were predicting that a long, hot summer of brownouts and blackouts lay ahead. The governor was negotiating bailout deals with the utility companies that would have them sell their entire transmission systems to the state for prices that were well above book value. In March the CPUC, for the first time since the energy crisis hit, granted the utility companies across-the-board rate increases of ten percent. Nevertheless, negotiations with PG&E broke down and the utility company declared bankruptcy. The negotiations with SCE eventually broke down too, although SCE avoided bankruptcy.

The state's electricity generators were desperately searching for a way to get the utility companies to pay them. A deal was struck in late March at the CPUC that allowed the utility companies to resume payments to the power generators on a going-forward basis, with the matter of payments for past due bills left unresolved. None of the thirty operating biomass facilities had been forced to shutdown, although many were severely stretched. Short-run avoided cost rates hovered in the neighborhood of 10¢/kWh through the Spring of 2001, well below their unbelievable levels of December and January, but still some three times higher than historical levels.

With the collapse of the state power exchange and the crippled financial status of the utility companies, the emergency session of the state legislature passed legislation that allowed the state, through the Department of Water Resources (DWR), to begin buying electricity on behalf of the state's consumers. DWR immediately set up a trading unit and created an exchange for short-term energy purchases. In addition to purchasing energy on a short-term basis the DWR embarked on a program of negotiating long-term energy contracts at prices below the then prevailing rates, but above historical levels. Many of the state's generators were eager to join the negotiations, and the state began to deal.

The ten idled biomass generating facilities in the state that had initiated startup preparations during late 2000 and early 2001 looked at long-term contracts with the state as the obvious way to go. At first they were rebuffed. DWR's initial request for proposals specified a minimum generating unit size of 50 MW. This excluded all of the candidate biomass facilities. One of the potential biomass startups, the 13.5 MW Soledad facility, applied to DWR in spite of not meeting the size qualification. They explained on their application that they understood they were undersized, but hoped that DWR would consider them for what they were, which included the possibility of starting up before the crucial summer season just ahead. The remaining biomass restarts waited to enter into negotiations with DWR until after the first wave of applications from the large producers had entered into negotiations.

In parallel with the state's efforts to negotiate long-term contracts with large generators, the CPUC developed a program to allow biomass facilities operating under old standard offer PPAs to select a five-year fixed price payment of 5.37 ¢/kWh, instead of being paid at variable short-term market rates. Many, but not all, of the biomass facilities operating under standard offer contracts accepted this offer, and began receiving the fixed price payments beginning in July 2001.

At this point the biomass power plants in California could be divided into two functional groups based on their power sales arrangements. The first group, which included most of the facilities operating under the old standard offer PPAs, had fixed price agreements that would cover the next five years, with prices that were high enough to ensure their continued ability to operate throughout this period. The second group, which included a few of the facilities that had operated continuously during the 1990s, and most of the facilities that were in various stages of restarting, were stuck without long-term PPAs. The already operating facilities in this group were selling their output on the short-term market, where prices were in the neighborhood of 10 ¢/kWh during the spring of 2001. Many of the facilities in this group were actively negotiating long-term contracts (five years or more) with the DWR. A few were content to remain players in the short-term market.

Available power supplies for the California grid remained at very low levels during the spring of 2001, as unusually large numbers of the state's fossil fuel-fired power plants seemed to be out of operation for servicing, many for prolonged periods of time. A couple of rolling blackouts of two or three hours duration each were imposed on many PG&E customers, despite the fact that spring is traditionally a period of low electrical demand in the state. Rumors and charges began to surface that some of the state's largest generators were manipulating their production units to game the market. The state was petitioning the FERC to impose price controls on the wholesale market, but the FERC was resistant. The situation was rapidly coming to a boiling point.

By the beginning of the summer of 2001, the DWR had signed some forty long-term contracts with generators for more than 10,000 MW of power. Although the contracts were not made public, prices were rumored to be in the range of 7 - 10¢/kWh, with terms ranging from 2 - 10 years. Soledad's gamble had paid off. Their biomass power plant was among the recipients of the first set of DWR contracts, and was already firing fuel. Seven of the biomass restarts were now actively engaged in negotiations with DWR. The other two attempted restarts, twin 10 MW facilities near Chowchilla (Chow II and El Nido), suspended their efforts to restart.

The newspapers continued to be full of dire warnings of looming summer blackouts. The crisis was beginning to spread to the entire Western U.S., and electricity supplies were reportedly strained in the Northeast. The Governor pushed hard for conservation in California, and for FERC price caps to be imposed in Washington. Finally FERC acted and imposed price caps on the wholesale electric market in the western U.S.

Then something totally unexpected happened. The long-dreaded summer of 2001 had arrived. But wholesale energy prices fell from May to June by more than a third, despite the fact that it was the beginning of the peak demand season. By the middle of the summer prices had fallen below four cents per kWh, which was within the range of pre-crisis levels. Not one blackout occurred during the entire summer. A combination of factors, including aggressive conservation efforts by consumers, an economic recession, an unusually cool summer, the long-term contracts signed by the DWR, the end of the drought in the Northwest, and the breaking of the bottleneck in the natural gas market, seemed to have combined to knock out the energy crisis. The FERC price caps were reached a couple of times soon after their imposition, then quickly became irrelevant. By late summer there were grumblings that the state had signed too many contracts at too high prices. There were even periods when the state was purchasing more contract electricity than it could use, and had to sell the excess into the out-of-state markets at a loss.

More than 99 percent of the long-term contracts the state signed in the spring of 2001 were for energy generated from natural-gas fired power plants, a result of the crisis atmosphere that had been in effect when the DWR began to seek long-term power supplies. Due to size and other considerations, renewables had been put on the back burner in the spring, and were just coming up for consideration at the DWR as the summer reached its peak, and the energy crisis ebbed.

Timing was distinctly against the biomass facilities. The DWR was coming under fire for the contracts they had just signed with the natural gas generators. Negotiations for additional long-term power purchase contracts suddenly ground to a halt, even in cases where there were signed letters of intent for power to be purchased from clean generating sources. Biomass project proponents complained that their questions went unanswered, and their phone calls were not returned. With the exception of Soledad, all of the other facilities attempting to restart, as well as several operating biomass power plants that did not have standard offer PPAs, found themselves relegated to selling into the short-term market at prices that were insufficient to cover their fuel and operating costs.

One of the many actions taken by the emergency session of the state legislature was the creation of the California Power Authority (CPA), which began operations in August 2001. The CPA was vested with $5 billion in bonding authority to invest in generating assets that would give the state power grid an adequate reserve margin of generating capacity. A minimum of $1 billion of the total was earmarked for conservation and renewables. Soon after its creation, the CPA put out a request for proposals, asking for any kind of proposal that a proposer wished to make. They were particularly interested in peakers, renewables, efficiency, and any kind of generator that would be located in known voltage-constrained regions. All of the biomass facilities that were negotiating with the DWR filed applications for their projects with the CPA.

One of the CPA's mandates was to produce, within six moths of its creation, an investment plan for its $5 billion capital fund. The investment plan had to be submitted to the legislature by the middle of February 2002. A series of meetings were held around the state to solicit public input, and a strategic document was hashed out. The official document rejected the notion of having the CPA support the development of a new generation of natural gas-fired peaking plants in California, and enthusiastically embraced renewables. In particular, the CPA *Investment Plan* recognizes the importance of maintaining and enhancing the state's biomass generating infrastructure, and stated an intention to contract with the biomass generators who did not have standard-offer contracts, and had so far been unable to negotiate contracts with the DWR.

Despite their good intentions with regards to biomass, the CPA has been thwarted in their efforts to move forward with any biomass contracts. The problem is that, due to a dispute between the state and the CPUC over regulatory jurisdictional issues, the CPA, in concert with the state Treasurer's Office, is unwilling to issue the bonds that will supply the funds they need in order to make commitments to generating facilities. At the present time the state underwriters have taken the position that the state lacks the authority to ensure that ratepayers will be held fully responsible for the costs of energy procurement. They will not issue the CPA bonds until the guarantees they are seeking are in place.

December 2001 was the sixth consecutive month in which short-run avoided cost rates were insufficient to cover all of the costs of biomass power generation. The group of facilities that did not have long-term contracts were nearing the end of their ability to hang on, a finding that was recognized and confirmed by the CPA, the DWR, and the Governor's Office. One project, Capital Power Ione, an 18 MW facility, was able to finalize a contract with DWR during the last months of 2001. This project had obtained a signed letter of intent with DWR in the early spring, and continued to negotiate faithfully throughout the summer and fall, enlisting support wherever it could be found. They were finally able to come to terms that were substantially less favorable than those that had been granted to the natural gas industry earlier in the year. This was the second, and so far last, of the restarts that has managed to finalize a long-term power purchase agreement with the state.

Recognizing that the issues that were holding up the issuance of the CPA's bonds were not going to be resolved quickly, the DWR, in conjunction with the CPA, signed 90-day interim contracts with eleven facilities before the end of the year, with a common intention to enter into long-term contracts as soon as it became possible. The interim contracts were extended for a second 90-day period at the end of March, carrying these facilities through the end of June 2002.

The interim contracts provide for average revenues of 6.5¢/kWh, differentiated by time-of-use and seasonal factors. The payment level covers both energy and capacity, and as such is below the level earned by the facilities with old standard offer utilities contracts (5.37 ¢/kWh energy plus 2.0 ¢/kWh capacity), and on the low side of the range of the legitimate costs of energy production from biomass (see Morris, G., *Biomass Energy Production in California: The Case for a Biomass Policy Initiative*, NREL Report No. NREL/SR-570-28805, November 2000).

California currently has thirty-five biomass power plants in operation, representing a total of 685 MW of electricity generating capacity. Approximately two-thirds of the total are operating under old standard-offer power purchase agreements with fixed energy prices that will remain in effect through the middle of 2006. These facilities are well served by their contracts, and should be able to operate viably until at least that time. The other one-third of California's biomass power plants are operating under interim 90-day contracts that provide them with minimally acceptable operating revenues. The long-term fate of this group of facilities is a function of whether they are ultimately able to obtain longer-term contracts with adequate power purchase provisions.

Lessons Learned - Existing Industry[7]

This discussion includes summary information on 20 biomass power plants—18 in the United States, one in Canada, and one in Finland, which represent some of the leaders in the industry. Table 4.1 lists the 20 plants in order of on-line date, the same order in which they are presented in the report. In some cases, the on-line date means the date an older fossil-fired plant started using biomass fuel commercially (not its original on-line date). Some of the information in the table is abbreviated, but can be clarified by referring to the specific plant sections.

The on-line dates of the plants span about 18 years, from December 1979 to January 1998. The types of biomass fuels used are abbreviated: "mill" refers to mill wastes, etc. Many boiler types are represented: six traveling grate stoker boilers, four water-cooled vibrating grate boilers, four bubbling fluidized bed combustors (FBCs), one circulating fluidized bed (CFB) boiler, one fixed-grate boiler, one sloping grate boiler, and two pulverized coal (PC) boilers retrofitted to cofire solid or gasified biomass. Steam temperatures for the biomass-fired boilers are 750˚-980˚F; for the PC boilers, 1,004˚-1,005˚F. The nominal sizes of the plants range from 10 MW to 79.5 MW.

Electricity Generation and Fuel Consumption

Table 4.2 lists the plants in order of electricity generation, in gigawatt-hours/yr (GWh/yr). For some plants, the generation numbers are actual statistics from a recent year (1996, 1997, or 1998). For plants that did not provide these statistics, the generation rates were estimated based on available information. The same is true for the annual capacity factors (CFs, %) and net plant heat rates (Btu/kWh). The biomass fuel consumptions were calculated by multiplying GWh/yr times Btu/kWh, and dividing by 8.5 million Btu/t (4250 Btu/lb, or 8500 Btu/dry lb with 50% moisture content).

Capacity Factors

Annual CFs range from 19% to 106%. Some plants with low CFs (e.g., Multitrade and McNeil) are peaking units. The plants with very high CFs have special circumstances. Shasta and Colmac were still under the first 10 years of California Standard Offer contracts when the data were obtained. Williams Lake can operate as high as 15% over its rated capacity, and can frequently sell extra power.

Heat Rates

The Williams Lake plant also holds the distinction of having the largest single boiler (60 MW) and the lowest heat rate (11,700 Btu/kWh) of any 100% biomass-fired power plant. Biomass-cofired coal plants can achieve slightly lower heat rates, as exemplified by Greenidge Station (11,000 Btu/kWh on the biomass portion of the fuel, compared to 9818 on coal alone). The least efficient plants in this report have heat rates of about 20,000 Btu/kWh. A "typical" value is about 14,000 Btu/kWh (24.4% thermal efficiency, HHV).

Cogeneration

The four cogeneration plants in the report—Okeelanta, Snohomish, Lahti, and Camas—are recent plants, using the latest technology, in traditional niches for biomass power: two at pulp and paper mills (Snohomish and Camas), one at a sugar mill (Okeelanta), and one at a municipal district heating plant (Lahti). The estimates given in Table 4.2 for these plants represent only the solid fuel biomass portion of the energy input. At the two pulp and paper mills, recovery boilers produce large fractions of the total steam from waste liquor; the wood waste boilers at these facilities constitute focus of this report. At Lahti, coal and natural gas produce most of the energy; wood wastes and refuse derived fuel (RDF) are fed to a

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[7]Excerpted from Wiltsee, G. (2000). "Lessons learned from existing biomass power plants," NREL/SR-570-29-6946, National Renewable Energy Laboratory, Golden, CO.

gasifier that supplies low-Btu gas to the boiler. The Okeelanta cogeneration plant burns bagasse for about 6 months of the year, and burns urban and other wood wastes at other times.

Table 4.3: Summary of Biomass Power Plants in this Report

Plant	Location	MWe	GWh/yr	CF, %	Btu/kWh	Tons/yr*
Williams Lake	British Columbia	60.0	558	106	11,700	768,000
Okeelanta (cogen)	Florida	74.0	454	70	13,000	694,000
Shasta	California	49.9	418	96	17,200	846,000
Colmac	California	49.0	393	90	12,400	573,000
Stratton	Maine	45.0	353	90	13,500	561,000
Kettle Falls	Washington	46.0	327	82	14,100	542,000
Snohomish (cogen)	Washington	39.0	205	60	17,000	410,000
Ridge	Florida	40.0	200	57	16,000	376,000
Grayling	Michigan	36.0	200	63	13,600	320,000
Bay Front	Wisconsin	30.0	164	62	13,000	251,000
McNeil	Vermont	50.0	155	35	14,000	255,000
Lahti (cogen)	Finland	25.0	153	70	14,000	252,000
Multitrade	Virginia	79.5	133	19	14,000	219,000
Madera	California	25.0	131	60	20,000	308,000
Tracy	California	18.5	130	80	14,000	214,000
Camas (cogen)	Washington	17.0	97	65	17,000	194,000
Tacoma	Washington	40.0	94	27	20,000	221,000
Greenidge	New York	10.8	76	80	11,000	98,000
Chowchilla II	California	10.0	53	60	20,000	125,000
El Nido	California	10.0	53	60	20,000	125,000

*Tons/year are calculated, assuming 4250 Btu/lb.

Table 4.4: Plant Electricity Generation and Biomass Fuel Consumption Estimates

Plant	Online	Fuels	Boiler(s)	lb/hr	Psig	ÞF	MWe
Bay Front	Dec-79	Mill, TDF, coal	2 modified coal stokers	280,000			30
Kettle Falls	Dec-83	Mill	1 traveling grate stoker	415,000	1500	950	46
McNeil	Jun-84	Forest, mill, urban	1 traveling grate stoker	480,000	1275	950	50
Shasta	Dec-87	Mill, forest, ag,	3 traveling grate stokers	510,000	900	905	49.9
El Nido (closed)	Oct-88	Ag, forest, mill,	1 bubbling FBC	130,000	650	750	10
Madera (closed)	Jul-89	Ag, forest, mill,	1 bubbling FBC	260,000	850	850	25
Stratton	Nov-89	Mill, forest	1 traveling grate stoker	400,000	1485	955	45
Chowchilla II (closed)	Feb-90	Ag, forest, mill,	1 bubbling FBC	130,000	650	750	10
Tracy	Dec-90	Ag, urban	1 water-cooled vib grate				18.5
Tacoma (cofiring)	Aug-91	Wood, RDF, coal	2 bubbling FBCs		400	750	12
Colmac	Feb-92	Urban, ag, coke	2 CFB boilers	464,000	1255	925	49
Grayling	Aug-92	Mill, forest	1 traveling grate stoker	330,000	1280	950	36.17
Williams Lake	Apr-93	Mill	1 water-cooled vib grate	561,750	1575	950	60
Multitrade	Jun-94	Mill	3 fixed grate stokers	726,000	1500	950	79.5
Ridge	Aug-94	Urban, tires, LFG	1 traveling grate stoker	345,000	1500	980	40
Greenidge (cofiring)	Oct-94	Manufacturing	1 tangentially-fired PC	665,000	1465	1005	10.8*
Camas (cogen)	Dec-95	Mill	1 water-cooled vib grate	220,000	600	750	38-48
Snohomish (cogen)	Aug-96	Mill, urban	1 sloping grate	435,000	825	850	43
Okeelanta (cogen)	Jan-97	Bagasse, urban,	3 water-cooled vib grate	1,320,000	1525	955	74
Lahti (cofiring, cogen)	Jan-98	Urban, RDF	1 CFB gasifier + PC	992,000	2500	1004	25**

*108 total net MW, 10% from wood and 90% from coal.
**167 total net MW, 15% from biofuels and 85% from coal.

Fuels

The cost of biomass fuel from mill wastes and urban wood wastes can range from about $0/MBtu to about $1.40/MBtu, depending on the distance from the fuel source to the power plant. Getting to zero fuel cost depends on locating a power plant in an urban area next to a wood waste processor, or next to a large sawmill or group of sawmills. Deregulation will make this zero fuel cost strategy more important in the future.

Agricultural residues (primarily orchard tree removals) can be processed into fuel and delivered to nearby biomass power plants for about $1/MBtu. Only if open burning of residues is prohibited will transferring some of this cost to the orchard owners be possible.

Forest residues are much more costly ($2.40-$3.50/MBtu), because of the high costs of gathering the material in remote and difficult terrain, processing it to fuel, and transporting it to power plants. There are strong arguments for government programs to bear the costs of forest management and (in the West) fire prevention. Only if such programs are created will forest residues be as cost-competitive fuel as in the future.

Plants that have come close to zero fuel cost are Williams Lake, which is located very close to five large sawmills, and Ridge, which accepts raw urban wood wastes and whole tires, and burns landfill gas. Other plants burning primarily mill wastes include Shasta, Kettle Falls, Stratton, Snohomish, Grayling, Bay Front, Multitrade, and Camas. Other plants burning primarily urban wood wastes (and in some cases RDF) are Okeelanta, Colmac, Lahti, and Tacoma. Sawdust from furniture manufacturing is the main biomass fuel at the Greenidge plant. Plants burning agricultural residues include Okeelanta, Tracy, Madera, Chowchilla II, and El Nido. Plants burning significant amounts of forest residues include McNeil, Shasta, Stratton, and Grayling.

Lessons Learned

The project experiences described in the following sections capture some important lessons learned that lead in the direction of an improved biomass power industry. Undoubtedly, many other problems and solutions did not surface in the interviews and in the documents and articles that served as source materials. A summary of the lessons learned from these 20 biomass plants follows; in each category an effort is made to identify plants that illustrate particular points, so the reader can go to those sections to learn more.

Fuel

The highest priority at most biomass power plants is to obtain the lowest-cost fuels possible. This involves tradeoffs in fuel quality, affects the design and operation of the system, and frequently is limited by permit requirements. Some fuel-related lessons illustrated in this report are:

- At Bay Front, the conversion from coal and oil to biomass and other waste fuels kept an old generating station operating and provided continued employment.
- At the McNeil Station, long-term fuel contracts insisted on by financing institutions created some costly problems. As required, McNeil had 15 or 20 long- term fuel contracts when it started up. The CF dropped because of dispatch requirements, resulting in lawsuits and settlements with fuel suppliers and odors from the wood piles. The plant now runs more economically by buying wood fuel under short-term contracts.
- Maintaining adequate fuel supply in the midst of a declining regional timber industry has been the single biggest challenge for the Shasta plant. Almost from startup, Shasta has tried to diversify its fuel sources. From an initial list of permitted fuels that included only mill waste, logging/thinning residue, and cull logs, Shasta added agricultural residues, fiber farm residues, land and road clearing wood wastes, tree trimmings and yard wastes, and natural gas.

- The San Joaquin Valley Energy Partners plants (Chowchilla II, El Nido, and Madera) experimented in combusting low-cost, low-demand agricultural waste materials such as grape pomace, green waste, onion and garlic skins, and bedding materials not desired by competing facilities. However, the most difficult-to-burn agricultural residues were assigned to the "tertiary" fuel category and mixed in small percentages with better fuels, primarily wood.
- Experience at the Tracy plant shows that urban wood waste can be a comparatively inexpensive fuel (~$0.35/MBtu) if the plant is located close to the urban area. Compared to urban wood waste, orchard wood is relatively expensive (~$1.00/MBtu) because growers are used to simply pushing and burning it, and are generally not willing to pay a fee to have the wood removed.
- Tacoma found that focusing on fuel cost (¢/kWh) rather than fuels that provide highest efficiency (Btu/kWh) saved the plant $600,000/yr. Opportunity fuels (with tipping fees) can eliminate fuel costs and generate net revenues. Fuel procurement should be one of the highest priorities and a full-time job.
- At the Williams Lake plant, with uncertainty in the forestry industry, unknown impacts of Asian market upheaval, high provincial stumpage fees, and closure of some coastal sawmills and pulp mills, the biggest threat to an enviable operating record appears to be fuel availability.
- The Ridge Generating Station is an urban waste recycling facility, working within the local waste management infrastructure to provide a low-cost recycling service to waste generators, and to obtain a free or negative-cost fuel mix (urban wood wastes, scrap tires, and landfill gas) for energy production.
- The Snohomish Cogeneration plant design anticipated the trend toward declining quantities of sawmill residues, and the increasing use of urban wood wastes in the region. Siting the plant at a paper mill provided an excellent fit for steam use, as well as expertise in wood waste handling and combustion.

<u>Fuel Yard and Fuel Feed System</u>

The area of a biomass power plant that can almost be counted on to be mentioned in response to the question "Have you had any significant problems or lessons learned?" is the fuel yard and fuel feed system. Most plants in this report spent significant time and money during the first year or two of operation, solving problems such as fuel pile odors and heating, excessive equipment wear, fuel hangups and bottlenecks in the feed system, tramp metal separation problems, wide fluctuations in fuel moisture to the boiler, etc., or making changes in the fuel yard to respond to market opportunities. Examples noted in this report include:

- At Bay Front Northern States Power (NSP) engineers installed and improved (over time) a system that allows feeding of 100% biomass, 100% coal, or any combination of the two. Because wood fuel quality varies more than coal quality, proper tuning of the automatic combustion controls is more important when firing wood. Operators must pay close attention and periodically adjust feeders.
- With the addition of a debarker, high-speed V-drum chipper, chip screen, and overhead bins, the Shasta plant was able to offer to custom chip logs, keeping the 35% of the log not suitable for chips. In times of low chip prices, Shasta still purchases the whole log. Shasta successfully marketed the program to some of the largest landowners in California.
- At Shasta, the operators learned to blend all the fuels into a homogeneous mixture that allowed the boilers to fire at a consistent rate and maintain maximum load under all conditions, without violating environmental standards, excessively corroding heat transfer surfaces, or slagging beyond the point where the boilers required cleaning more than twice per year.
- At Stratton, the original owners spent about $1.8 million during the first year of operation to improve the operation of the fuel yard.
- Tacoma personnel stress the need to take extra care at the beginning of the project with design of the fuel feed system. Selecting a proven fuel feed system is important.

- The only area of the Williams Lake plant that was modified after startup was the fuel handling system. Minor modifications were made to improve performance, such as adding the ability to reverse the dragchains on the dumper hoppers, to make it easier to unplug fuel jams; and adding three more rolls to each disk screen (12 rolls were provided originally), to reduce the carryover of fine particles that tended to plug up the hog.
- The Multitrade plant's minor problems included fuel feeding problems in the early days of operation (quickly corrected); erosion and corrosion in the fuel splitter boxes and conveyor belt shrouds (corrected by relining with plastic); and occasional heating and odor problems in the fuel pile until they learned not to let any part of the pile age more than 1 year.
- The Greenidge Station found that the technology for preparing biomass fuel for cofiring in a PC boiler needs further economic evaluation, research, and development. Grinders do not normally produce a product that has good flow characteristics. The wood fibers are sticky, stringy, and elongated when produced from a grinding operation. The fuel product needs to processed by equipment that produces a chip.

<u>Design for Fuel Flexibility</u>

Many biomass plants change fuels significantly over the years, as opportunities arise or old fuel sources dry up. These changes are often not predictable. The best strategy to deal with this problem is to have a plant design and permits that allow as much fuel flexibility as possible. For example:

- Bay Front was a coal-fired stoker plant that converted to wood firing and cofiring capability in 1979. Experience showed that ash fouling and slagging problems were much more severe when cofiring wood and coal than when firing either fuel alone. NSP now operates in either 100% coal or 100% wood firing mode.
- In 1989, the ability to burn natural gas was added to McNeil Station. Summer pricing for Canadian gas was more attractive than wood prices at that time. Six fossil fuel burners were installed, allowing full load capability (50 MW) on gas and 15 MW capability on No. 2 oil. Gas prices rose during the mid-1990s, and McNeil burned almost no natural gas from 1997 to 1998.
- At the Shasta plant, a large hammermill was added to the fuel processing system to allow the use of a broader range of fuels. This reduced fuel costs by allowing the plant to process opportunity fuels such as railroad ties, brush, and prunings.
- The Tacoma plant was constrained by a limited fuel supply and permit, and worked hard to develop more options to use opportunity fuels (tipping fee fuels, some of which are not biomass)—waste oil, asphalt shingles, petroleum coke, etc.
- Colmac found that modifying its permit to allow the use of petroleum coke was worthwhile. At times, waste fossil fuels can be more economical than biomass.
- The Ridge fuel yard can handle essentially any type or size of wood waste; its only restriction is that it will not accept palm trees. The simple and reliable traveling grate stoker boiler can burn these mixed wood wastes, including yard wastes, and can burn crude tire-derived fuel (TDF) and landfill gas. The emission control system with a lime spray dryer and baghouse can remove almost any significant pollutant encountered in these wastes.

<u>Location</u>

As realtors say, "Location, location, location!" Biomass residues and wastes are local fuels, with very low energy densities compared to fossil fuels. Transport costs become very significant after about 20 miles, and usually prohibitive beyond 100 or 200 miles. The ability to have the waste generators deliver the fuel to the plant site at their own expense requires a location very close to the sources of waste. There are also other considerations, such as the proximity to residential neighborhoods. For example:

- The primary lesson learned from the McNeil plant experience in Burlington, Vermont, is the need to pay careful attention to the siting of a biomass-fueled plant. Siting the plant in a residential neighborhood of a small city has caused a number of problems and extra expenses over the years:

a permit requirement to use trains for fuel supply, high taxes, high labor rates, local political involvement, and neighborhood complaints about odors and noise.

- The Colmac plant shows that urban wood waste can be a comparatively expensive fuel (~$1.50/MBtu) if the plant is located far outside the urban area. The transportation cost is significant. An urban biomass plant can derive income from its fuel with a location and tipping fees that attract wood waste generators with loads to dump.

Reliability and Dependability

Several plant managers with the best long-term operating records stressed the necessity for placing a high value on reliability and dependability. This is true during plant design and equipment selection, and during operation. For example:

- Outside of planned outages, the Kettle Falls plant has an availability factor of about 98% over a continuous 16-year period. The superintendent has high praise for the people on the staff. The plant is always exceptionally clean and neat.
- The Shasta general manager advises: “Always place a high value on reliability and dependability, for these will allow you to be considered a ‘player’ and thus a participant in the development of special programs with the utility.”
- At Williams Lake, which has an outstanding performance record, the chief engineer stressed that staying on top of maintenance programs at all times is essential.

Partnerships

The most successful projects have developed formal or informal partnerships with their key customers and suppliers. The relationship with the utility company that buys the power is usually the most important. This may change as generators simply bid their power into a power pool. Cogeneration plants by definition must have close relationships with their steam users. Sometimes there are a few large fuel suppliers (such as sawmills) with whom special relationships are crucial. Examples in this report that illustrate the importance of strong partnerships include:

- In the words of the Shasta general manager: “But these new approaches must go forward on a very different basis than our past biomass developments. They must go forward in partnership with utilities. While the utility may want to participate in such systems, they will not and cannot do so unless the cost to ratepayers is very close to that of other generating options.”
- Like several other biomass power plants, the Grayling Station is operated as a cycling plant. It has run at about a 70%-80% CF during peak demand periods, and at about a 40%-50% CF during off-peak periods. The McNeil, Multitrade, and Ridge plants are other examples of cycling plants.
- The arrangement between the Camas Mill and its electric utility (PacifiCorp) is mutually beneficial. The utility-financed turbine/generator provides the mill with an additional source of cash flow, without significantly changing the mill's steam generation and delivery system. The utility has added about 50 MW of reliable generating capacity to its system for a relatively small investment, and has strengthened its relationship with a major customer.
- The Okeelanta Cogeneration Plant provides many environmental benefits, and should serve as a reliable energy source for the sugar mill and the electric utility. Unfortunately, the owners and the utility could not amicably resolve their differences over a “standard offer” contract. The ensuing lawsuits, bankruptcy, shutdown, and layoffs significantly affected the project.

Cofiring

Once the availability of low-cost biomass fuel is established, the primary issue addressed in most retrofitted cofiring projects is how to feed the fuel (and in what form to feed it) to the coal-fired boiler. There are of course many other issues, such as effects on boiler operations, plant capacity, emissions, and ash quality. Some of these are highlighted by lessons learned at four plants in this report:

- Bay Front could use standard wood sizing and feeding equipment because its coal-fired boilers were stokers. Cofiring was possible at any ratio of wood to coal from 0% to 100%. However, slagging and fouling was very severe because of the interaction between the alkali in the wood and the sulfur in the coal.

- The bubbling FBCs at Tacoma can fire 0%-100% wood, 0%-50% coal, and 0%-50% RDF (permit limitation). The actual fuel mix on a heat input basis from 1993 to 1997 was 54%-68% waste wood, 12%-32% coal, and 12%-20% RDF. Opportunity fuels that command a tipping fee or can be obtained free became a high priority in 1997.
- The cofiring experience at Greenidge Station demonstrates that a separate fuel feed system can effectively feed wood wastes to a PC unit. The economics at this site are favorable; the difference between coal and wood prices is \$0.45-\$0.79/MBtu. The plant has continued to cofire wood and invest in system improvements since the testing began more than 4 years ago.
- The Lahti cofiring project at a PC- and natural gas-fired district heating and electric generation plant in Finland uses a CFB gasifier to convert wood wastes and RDF to low-Btu gas that is burned in the boiler. The operation has been technically successful for 1 year, and gives utilities in the United States another option to consider when examining the feasibility of cofiring biomass and waste fuels in coal-fired boilers.

<u>Benefits</u>

The 20 biomass projects in this report provide many concrete illustrations of environmental and economic benefits. The Kettle Falls, Williams Lake, and Multitrade plants provide air quality benefits in rural settings where sawmills used to pollute the air with teepee burners. The Ridge, Tacoma, and Lahti plants serve urban areas by burning urban waste fuels cleanly; Lahti provides district heat as well. The Okeelanta, Tracy, and San Joaquin plants burn agricultural residues cleanly, which formerly were burned with no emission controls. The Shasta, McNeil, and Grayling plants serve the forest management operations in their areas by cleanly burning unmerchantable wood, brush, and limbs. For example:

- The Bay Front plant was being considered for phase out as larger, more efficient units came on line in the NSP system. Adding the ability to use biomass fuel kept the plant operating, saved jobs, and improved waste management.
- Long-term residents in the Kettle Falls area reported major reductions in haze after the plant went into operation. The plant improved air quality by eliminating numerous wigwam burners formerly used to dispose of mill wastes.
- In the forests near the Shasta plant: “The result is a healthier, faster growing forest that has a dramatically lowered potential to be destroyed by fire. There are now adequate moisture, nutrients and sunlight for the remaining trees and net growth often triples. The remaining trees regain their traditional resistance to insect and disease attack.”
- The Grayling and Ridge projects were planned and the plants were designed with waste management roles in mind—one in a rural setting and the other in an urban setting. Efforts were made to fit constructively into the local economic and environmental landscapes, with clearly positive results.

<u>Subsidy Programs Do Not Last</u>

As a final note, the Shasta general manager’s list of lessons learned includes this one: “Beware of entering a regulatory system in which the utility commission or legislature has determined that it is acceptable for ratepayers to pay the full cost of your technology. Such things do not last.”

DOE Hawaii Project Lessons Learned

This section discusses the "Hawaii Gasification Facility" project. The pilot facility is shown in Figure 4.8. The purpose is to review the chronology of major milestones for the project, and to discuss lessons learned from the project.

Figure 4.8: Hawaii Gasification Facility

Project Chronology

- DOE Request for Proposal Issued
- DOE Reorganization
- Cooperative Agreement, DOE and PICHTR

1994: Phase 1 Plant Completion
1995: Phase 1 Experimental Completion
1996: Cooperative Agreement, DOE and Westinghouse
1997: Plant Modifications Complete
1997: Initial Westinghouse Experiments Performed
1997: Westinghouse Experimental Work Stopped
1998: Project Stopped

Project Overview

The solicitation for the project "Federal Assistance Solicitation for Cooperative Agreement Proposals DE-PS02-89CH10407 for a Biomass Gasifier Scale-up Facility" was issued by the DOE SERI Area Office July 31, 1989, (DOE 1989) with a proposal due date of November 28, 1989. The solicitation was a reissue of a solicitation issued in 1986 by the DOE Richlands Office, in which the proposals were withdrawn during the final negotiation stage.

The abstract of the solicitation stated that DOE desired to share with a U.S. citizen, U.S. corporation, or a state or local government the cost of a project to design, construct, start-up, test and evaluate an experimental scale-up facility to produce a medium-BTU gas (300-500 BTU/scf) from the thermochemical conversion of biofuel feedstocks. DOE intended that the facility provide industry with the engineering data necessary for the commercialization of the technology and that the facility serve as a centerpiece from which DOE and industry could develop additional capabilities such as the conversion of medium-BTU gas to methanol. It was stated that a majority of the medium-BTU gas produced by the facility be available for sale or used to provide data on gas utilization and to support facility operations; however a portion of the gas was to be made available for experimental purposes such as gas cleanup, compression, water-gas shift reactions, and/or synthesis gas reactions.

Other requirements were:

1. The gasification system was to be capable of processing 50 to 200 tons of feedstock per day.
2. Although not required, it was desirable that the facility be capable of handling a variety of biomass feedstocks. Fossil fuels were not allowed, except for start up.
3. The system was to allow for the later addition of process development units (PDUs) necessary to cool, shift, clean up, and compress the gas so that it was suitable for the production of liquid fuels such as methanol. The funding of such future PDUs was dependent on future negotiations and the availability of DOE funds.
4. The medium-BTU product gas was to be applied to a process to (a) provide an example of its usefulness as an energy product; (b) provide financial support to gasifier operations; and (c) provide for a complete technoeconomic evaluation of the process from feedstock preparation to gas utilization.
5. The project was to be constructed and operated within the 50 United States or the U.S. territorial possessions.
6. The DOE funding was to be limited to a maximum of 50% cost share with an upper limit of $5 million.

The Pacific International Center for High Technology Research (PICHTR), Honolulu, Hawaii proposed a project at Paia, Maui, Hawaii to scale-up the Institute of Gas Technology (IGT) RENUGAS® biomass gasification technology. The total proposal cost was $11.8 million, with a DOE cost share of $5 million (PICHTR 1989). PICHTR was selected by DOE for negotiation, and on September 30, 1991 a cooperative agreement was awarded to PICHTR for $9,156,904. DOE's share was $5,000,000; the State of Hawaii, with contributions from the Ralph M. Parsons Company and Hawaii Commercial and Sugar Company (HC&S), was $4,156,904. The following purpose for the project was given:

> "*The purpose of this cooperative agreement is: To design, construct and operate a biomass gasification facility to produce medium-Btu gas. The gas will be suitable for use as a gaseous fuel or for upgrading to a synthesis gas for conversion to liquid transportation fuels or utilization in a gas turbine for electrical energy production. This effort will also provide scale-up and operating engineering data from which the commercial feasibility of the gasification technology employed can be assessed. Upon completion of the initial program, an ongoing two-part Phase 2*

Program is anticipated. Part 1 would be primarily oriented toward electrical production; Part 2 toward biomass fuels or methanol production."

In addition, although the stated purpose of the project was to produce a medium-Btu gas, initial design and operation would be as an air-blown gasifier to produce a low-Btu gas (150 Btu/scf), with limited testing using bottled oxygen to produce a medium-Btu gas (Kearns, 1991). This change was instituted to reduce project costs.

PICHTR - Phase I

Between 1991 and 1996 PICHTR directed the Phase 1 cooperative agreement. PICHTR was assisted by a Project Oversight Board consisting of representatives of PICHTR, DOE, and the State of Hawaii. A technical advisory committee with members from DOE, PICHTR, NREL, IGT, and HNEI advised PICHTR on technical issues. During Phase 1 the basic unit was permitted, designed, constructed, and tested. A total of three test runs were conducted in 1995. These initial tests operated the Biomass Gasification Facility (BGF) over a range of 20 to 50 tons per day of bagasse. Operating pressures ranged from 28 to 100 psi, and operating temperatures were from 1,000°F to 1,650°F. The range of product gas higher heating value was 81.5 - 155.5 BTU/scf, and carbon conversion efficiencies of 95.4% - 98.7% were obtained. Total running time for the tests was 108 hours, during which time 165 tons of wet bagasse were gasified. The Phase 1 effort was summarized in a final summary report (Trenka, et al 1997).

A number of system limitation and problems were identified, primarily with components of the bagasse feeding system, including:

- Feed rate out of the walking floor was non-uniform due to batch feed from a front end loader and minimal leveling using a leveling bar. PICHTR recommended the use of doffing rolls in future tests.
- Problems were encountered in maintaining dryer throughput because of choking of the inlet rotary valve and buildup of bagasse in the dryer. The buildup of bagasse in the dryer was believed to be caused by the high degree of variability in bagasse moisture content. Later analysis by the vendor during the Westinghouse operations would show that the solids buildup was caused by improper operation, and that when air flows were properly set that the dryer operation was not a problem.
- Blow over of stones and plastic drip tubing to the downstream feed system caused excessive wear and plugged blower screens.
- The metering feeder to feed the weigh belt was grossly oversized for the feed rates used in Phase 1 and, in fact, did not meter feed. Therefore, feed fluctuations caused by the walking floor were not evened out, and uneven feed was delivered to the plug-screw feeder.
- The weigh belt performed well mechanically. However, variations in belt weight (splices, etc.) gave varying tare weights and masked variations in bagasse feed rate. Therefore, actual flow rate was only known within 10-15 %.
- The original concept was to use two plug-screw feeders in series, because the vendor believed that a maximum pressure seal of 150 psi per feeder was all that could be obtained. Therefore, a vertical space was left between the weigh belt and the plug-screw feeder to accommodate installation of a second feeder when higher-pressure operations were attempted. A tapered down-comer chute was installed between the weigh belt and plug-screw feeder. This chute, in combination with other system limitations, caused the majority of problems with the plug-screw feeder. Bagasse, shown below in Figure 4.9, has a bimodal particle size distribution.

Figure 4.9: Bagasse

The majority of the bagasse consists of very fibrous material. A certain fraction is the 'pith' of the original sugar cane and is non-fibrous in nature. During unit start up, bagasse feed was recycled back to the walking floor. During this operation, pith dust built up in the chute leading to the metering feeder. When the metering feeder started, this pocket of pith dust moved as a unit through the weigh belt to the chute and on to the plug-screw feeder. The plug screw feeder is designed to use the fibrous nature of biomass to mechanically move the material through the feeder. When a pocket of non-fibrous material was encountered a center plug would break free and the feeder would no longer work. This made start up very difficult. Small pockets of pith dust normally caused no problem, but in some instances the plug-screw feeder chute would tend to segregate pith causing non-fibrous pockets to reach the feeder. The variable fiber content also caused the density of the plug to vary, causing blow-backs under pressure, leading to unit shut-down.

- Other problems encountered with the plug-screw feeder included speed mismatches with the upstream feed delivery system. If the speed of the feeder was too fast, the plug was lost, causing blow-backs. If the speed of the screw was too slow, feed built up in the inlet chute and plugged. In addition, if the feed was too dry, excessive friction led to high current draws on the feeder motor and feeder shutdown. The feeder design could have been modified to fix the majority of the mechanical problems. The addition of a barrel lubricator would have lessened the friction and barrel wear and permitted operation with dry feed. The installation of a two-piece barrel would have greatly lessened the time to correct plug problems.

- The shredder conveyor was used to feed bagasse from the plug-screw feeder to the gasifier. This conveyor worked fine, but seal design made it difficult to hold pressure.
- The gasifier air-spargers tended to plug during periods of pressure variations. A design change was indicated.
- The back pressure valve tended to plug, and system pressure was controlled with the back-pressure bypass valve. It was not clear whether the basic design of the valve was incorrect, or whether the fluctuations in system operation was causing excessive blow-out of fluid-bed media.

The Phase 1 effort was contractually completed with the operation of the gasifier for 100 hours.

Westinghouse Electric Corporation Technology Validation Phase

Westinghouse Electric Corporation (WEC) was chosen by DOE as the lead organization for the second phase of the Hawaii project, called the Technology Validation Phase (TVP). WEC was chosen because of their interest in commercially developing the gasification technology and their interest in moving ahead with a commercial demonstration in the Hawaiian islands. WEC was supported in the TVP by PICHTR, the Institute of Gas Technology, the Hawaii Natural Energy Institute, and the Hawaii Commercial and Sugar Company. Funding was supplied by DOE, the State of Hawaii, and WEC. The State of Hawaii funding included $2 million for the TVP, plus $2 million conditional on establishing a commercial project in the islands. The Project Oversight Board and Technical Advisory Committee were disbanded.

The objective the Technology Validation Phase of the Hawaii Project was

1. To operate the gasifier for a total of 1500 hours at 100 tpd, 300 psi, and with a slip-stream hot-gas filter unit in operation,
2. To demonstrate sustained mechanical reliability of the overall core system (including the feed system and gasifier and their support systems) and the hot-gas filter system,
3. To determine plant performance, including
    - gas quality/variability
        - focusing on gas turbine needs
        - permitting baseline
    - up-load response time
    - turndown limits (3:1)
    - hot-gas filter system performance
        - operating temperature
        - cleanability
        - pressure drop across filter.

In addition to performing extended testing, WEC proposed extensive modifications to the BGF, including

- The plug-screw feeder was replaced. WEC stated "*The current plug-screw feeder must be replaced with a commercially viable system. After reviewing several alternate feed system designs, a lock-hopper feed system was selected for the program because of its commercial viability and operating experience on a wide range of fuels"* (Bartol 1996).
- An inert gas delivery system was added, to provide purge nitrogen for the lock-hopper system, and to provide additional purge gas for instruments and the gasifier.
- The air delivery system was upgraded to supply sufficient air for operation at 300 psi and 100 tpd.
- The front end of the feed system was modified to provide a cleaner, more uniform feed to the lock-hopper. Modifications included a new discharge assembly on the walking floor bin, a vibrating screen for oversize material removal, a destoner to remove small rocks, a chopper to

reduce the particle size to about minus 1 inch, a day-bin for intermediate dry feed storage, and a weigh bin to measure the amount of bagasse fed.

- A lock-hopper, designed by Thomas R. Miles Engineers, was installed to replace the plug-screw feeder.
- A pressurized metering bin was installed below the lock-hopper to convert the batch feed mode of the lock-hopper to a continuous mode.
- A collector screw was installed to transfer bagasse from the metering bin to the existing shredder conveyor.
- A hot-gas filter unit, sized for a 10 tpd equivalent slipstream, was installed downstream of the gasifier. This unit had been constructed and successfully operated by WEC at the IGT test facility in Chicago under subcontract to NREL. The unit was moved to Hawaii to perform long-term testing, since the pilot unit in Chicago was not designed for such operation.
- The system back-pressure valves were replaced with a design used by IGT in the Chicago pilot plant.

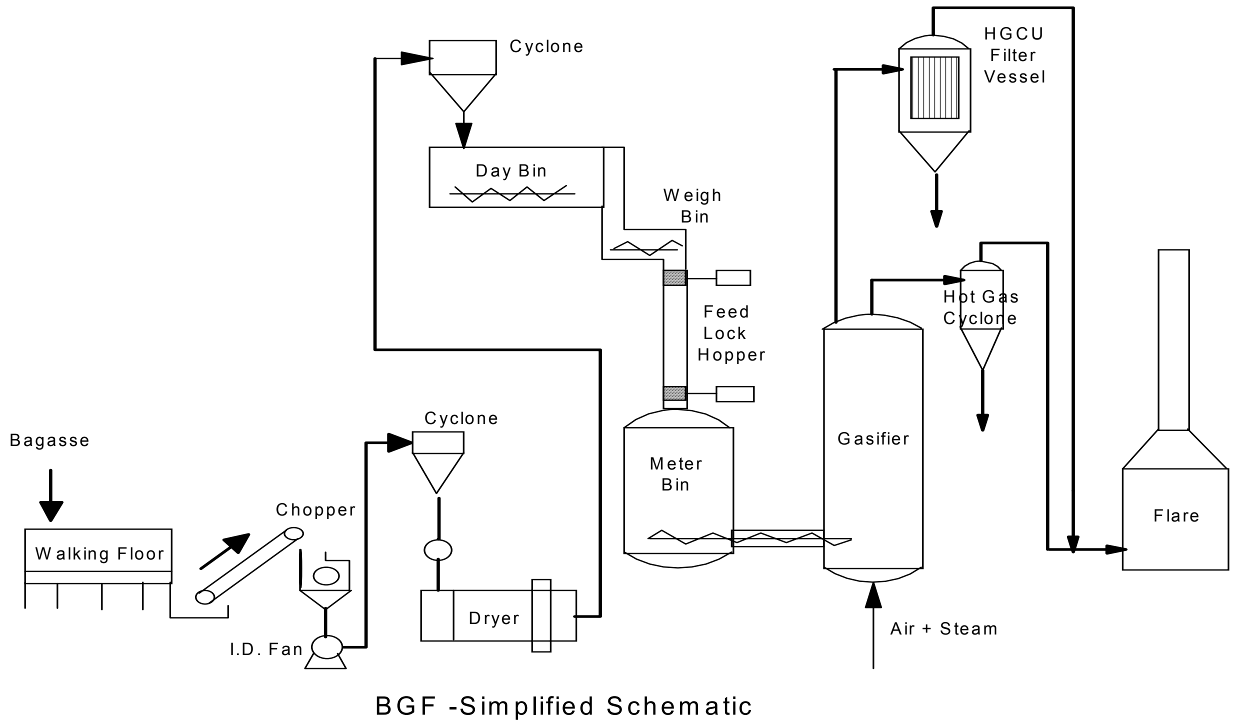

Figure 4.10: Gasifier Process Flow Diagram

The TVP Phase started in the summer of 1996, with a WEC estimated completion date of September 1997. A number of problems, briefly discussed below, were encountered and the TVP Phase was not completed by November 1997, at which time WEC determined that there were insufficient funds to complete the project.

A significant number of problems were encountered during the TVP. Given below is a summary of the problems.

- The schedule proposed by WEC was extremely ambitious, with no allowance for any major problems or delays. Insufficient funds were estimated to cover major delays.
- As a general statement, the majority of the equipment designed and installed during the TVP was undersized for operation at full capacity. Although the vendor had extensive experience in wood and straw handling systems, the direct applicability of items such as required horsepower was not correct. Based on the experience obtained during the TVP a rule of thumb would be to double the size of all motors if not based on previous operation with bagasse.
- Although doffing rolls were installed at the end of the walking floor to even out feed rate, the feed was still non-uniform. The basic problem was the walking floor.
- The vibratory conveyor was not long enough to permit good segregation of impurities. Modifications were made in the finger design to permit better flow, but very little separation of rock and plastic tubing occurred. The bagasse tended to make a mat which prevented bagasse from dropping through the fingers. When the fingers were enlarged almost everything dropped though.

- The destoner did a good job of separating stones out of the feed. The only problem was some blockage of the vacuum system.
- The primary problem with the chopper was that the original motor was undersized. A new motor was installed. Because of other problems with the feed system, screen size and shape was not optimized. Because of limited continuous operating time, a reliable estimate of required blade sharpening interval was not completed. Some capacity tests were performed at the completion of the TVP experimental program.
- The primary problems with the day bin were an incorrect screw rotation direction for the live bottom, motors incorrectly sized for bagasse, and the use of belt drives, instead of chain drives. All of these problems were corrected during the TVP. The day bin then worked correctly for traditional bagasse with a bulk density of 7 lb/ft^3. HC&S processed a new variety of sugar cane in 1997 which caused large problems with the sugar mill operation, including excess sugar in the bagasse and a higher bulk density of the bagasse. At times the bulk density of bagasse reached 11 lb/ft^3. Because all of the bins were designed for volumetric control of flow, the higher bulk density caused additional problems. These problems were overcome by reducing the solids inventory permitted in the bin.
- There were a number of problems with the lockhopper. The liner for the lockhopper was incorrectly fabricated. It did not extend to the bottom of the lockhopper. A sleeve was fabricated, but the welds seemed to cause some hangup of material. As a consequence, the lockhopper could not be filled to capacity, resulting in rapid cycling of the lockhopper to obtain throughput, and increased inert gas usage. A major reliability problem was encountered with the lock hopper valves. As bagasse built up on the rails, the valves would not move far enough for the limit switches to indicate that the valves were open or closed. The distributed control system interlocks would then stop operations. Many minor adjustments were tried during the tests, but were unsuccessful in giving reliable valve operation. The proposed solution involved modifying the connector between the valve and actuator with a universal joint with more tolerance, and the use of a hydraulic actuator instead of an air actuator. These changes would also require that the valve bonnet (a pressure vessel) be modified. These recommended changes were not made and tested during TVP operations.
- The metering bin had a basic design problem. The bin liner had a converging wall. It was not obvious from process schematics that this was the case. The converging wall caused plugging of the metering bin. The problem was solved by field installation of a straight wall. In addition, the level sensors in the bin did not work reliably, and a lot of time was involved in testing to obtain believable readings. This was critical since metering bin inventory was a key control variable for the feed system.
- The collector screw bearings caused problems throughout the TVP, although not bad enough to stop operations. At the end of the TVP a decision had been made to redesign the bearings. It was felt that the existing design would not permit operation for extended periods of time.
- Problems were encountered in plugging of the air sparge ring in the gasifier. Analysis showed degradation of the fluid-bed media was causing the problems. Because of supply problems a different media was used for the TVP than for Phase 1. The solution would seem to be to use the original media.
- Extreme problems were encountered on the back pressure control valve. The valve was a ceramic gate valve. On two occasions loss of pressure control was observed. When the valve was disassembled the ceramic gate was gone. Small pieces of ceramic were later found down-stream in the flare. Speculation is that during start-up and non-steady-state operations that some of the attemperator water was not vaporized and that liquid water impacted the valve gate causing thermal shocks that destroyed the gate. The valve was eventually replaced by the valve used in Phase 1.

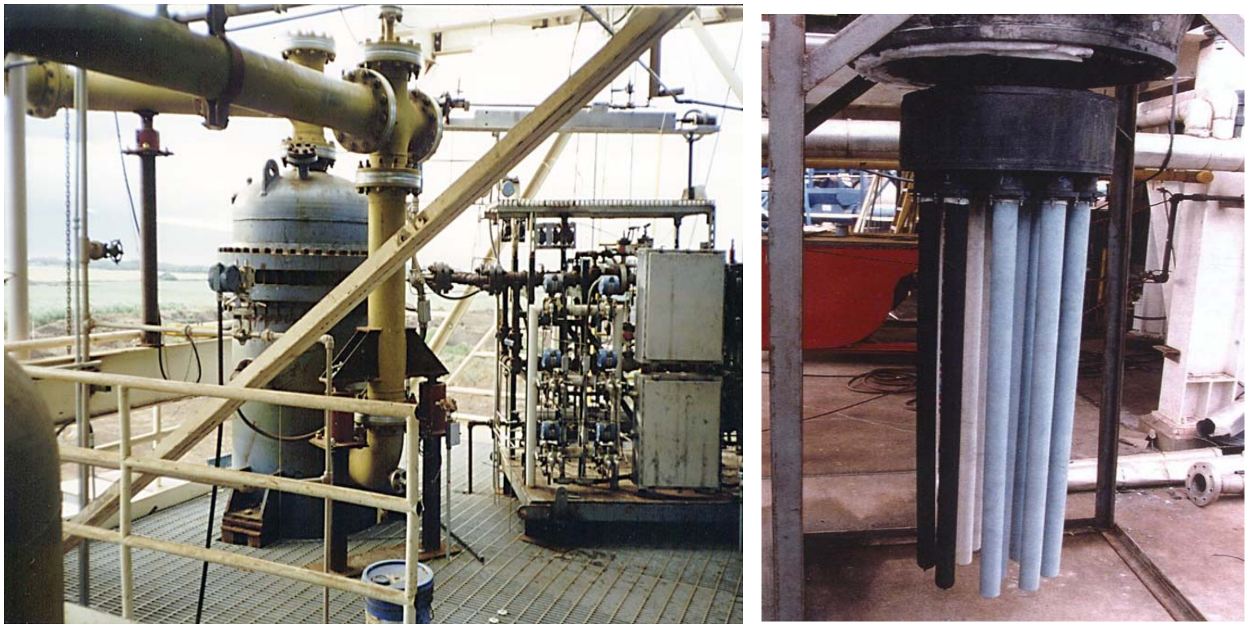

Figure 4-11: Hot Gas Filter Unit

Approximately 130 hours of gasification were achieved during the TVP. None of the operation was steady-state and only very limited gasification data were obtained. Filters were removed from the HGCU at the end of the test period and sent to WEC in Pittsburgh for analysis. Analytical results were presented in the WEC final report. Operations were stopped in November 1997 when WEC determined that there were insufficient funds to make needed modifications to the lock-hopper and continue operations.

Status

The TVP Phase of the Hawaii project was completed without reaching any of the major goals. In 1998 DOE completed an evaluation of future options and decided to discontinue participation in the project.

Summary of Lessons Learned

A brief summary of lessons learned for the Hawaii project is given below.

Non-technical

- Impact of Initial Cost Increase:

  Major experimental programs of this nature must have the leadership of a commercial E&C firm during the design and construction phase.

- Environmental Assessment:

  The most important lesson coming out of the environmental permitting process is that solicitations should require substantial environmental reviews before committing to the decision to proceed with a project. Given the time and expense to perform such reviews the time and cost impacts of environmental assessments should be included in project plans. To a large extent the

Biomass Power Program has learned from the Hawaii Project in this area. The Vermont Project was able to structure a project involving feeding the product gas to an existing boiler, without requiring a complete evaluation of the existing power plant permits, and using the using the existing boiler emission permits.

- Impact of the Energy Policy Act of 1992

  DOE was required to evaluate the project under the rules of EPACT92. Given the requirement by the State of Hawaii for commercial application for funding, a DOE determination was made that the project was a commercial, not an experimental, project. The conversion into a commercial project placed expectations on the project that could not be met.

  Commercialization required a number of conditions to be met. HS&S, the host company, needed to agree to assume ownership of the facility. They did not. Since the completion of the Hawaii project, HC&S has closed the Paia mill. Second, the facility was an experimental unit at a small scale. The capital cost of an experimental facility and the associated labor-intensive design (needed for experimental data gathering/analysis but not commercial operation) made the commercial cost of electricity uneconomic.

  Although the stated experimental goals were not reached in the proposed time, much valuable technical experience was gained in material handling systems, and in system integration. Therefore, the project was successful in addressing issues in start-up, testing and evaluation, and scaling up of biomass gasification technology.

- TVP Project:

  The advisory groups should not have been disbanded. On highly developmental projects of this nature, limiting technical input greatly increases technical risk.

<u>Technical</u>

- Impact of Initial Cost Increase:

  Bagasse is an extremely difficult feedstock. Organizations with direct operating and design experience should be involved in bagasse projects. Decisions to modify the feed system design to fit within the allowable funding did not recognize the potential for technical difficulties and led to the majority of operational difficulties through the life of the project.

- Phase 1 Equipment Decisions:

  Uniformity of feed is critical to the successful operation of a gasifier. The use of a feeder designed for a particular feed, rather than adaptation of a system not designed as a process feed system is needed.

- Phase 1 Equipment Decisions:

  We need to do a better job of evaluating the ability of the non-Federal partner to operate new equipment such as the plug-screw feeder. We probably would have had more success using a system closer to commercialization.

- Phase 1 Equipment Decisions:

We should more carefully evaluate the details of equipment. In the case of the plug-screw feeder, the use of a lubrication system would have eliminated many of the problems with overheating and high-current draws.

Minnesota Alfalfa Project

This section discusses the "Minnesota Agri-Power" project. The alfalfa biomass pilot separation facility in Priam, Minnesota is shown below. The purpose of this section is to review the chronology of major milestones for the project, and to discuss lessons learned.

Project chronology

1994 - DOE, NSP, and U of M complete feasibility study

1994 - DOE Biomass Power for Rural Development Request for Proposal

1996 - MnVAP purchases Priam, MN processing and separation facility

1996 - DOE and MnVAP execute a cooperative agreement for development of MAP

1997 - MnVAP and UPA execute a letter of intent to provide technical services

1997 - MnVAP and NSP execute a PPA

1998 - Enron Capital and Trade Resources Corporation and MnVAP execute a joint development agreement for co-ownership of the MAP Project

1998 - FERC approves MAP Project as an exempt wholesale generator

1999 - AAPA is allowed by the MPUC to submit comments opposing the PPA

1999 - Enron terminates the joint development agreement

1999 - DOE suspends funding and withdraws from participation

Project Overview

MnVAP was incorporated as a cooperative under chapter 308A of the laws of the State of Minnesota in December 1994. MnVAP is an agricultural cooperative, currently owned by nearly 500 alfalfa farmers in western Minnesota. The company was formed in response to the interest shown by DOE, USDA, and others, in the development of biomass electric projects that use farm-grown, closed loop energy crops as primary fuels.

A 1994 feasibility study of biomass power, funded by DOE and conducted by NSP, U of M, and several other renewable energy industry organizations, determined that alfalfa would be a viable energy crop. During this feasibility study, staff of NSP and U of M sought participation of farmers in southwestern Minnesota to appraise their interest in developing an alfalfa fuel production system. NSP sealed this realistic possibility by committing to obtain 125 MW of farm-grown closed-loop biomass power, and when DOE made a significant financial commitment to energy crop power systems with the BiomassPower for Rural Development initiative.

MnVAP's proposal for the Minnesota Agri-Power Project was submitted to the DOE in mid-1995. The project's goal was to demonstrate the commercial viability and environmental sustainability of an integrated energy crop and "new technology" biomass electric generation system. MnVAP Project Phase I of the cooperative agreement provided funding for technology testing, feedstock supply development, preliminary design, environmental review, and other preliminary business and project development tasks. Final design and construction of the MAP project would have been accomplished in Phase II.

In early 1995, NSP requested proposals to supply biomass generation resources to satisfy the first phase of the Biomass Mandate. MnVAP and its project team submitted two proposals to NSP: one for a biomass gasification combined-cycle power plant, and another for a conventional power generation plant. Each project would use alfalfa stems as a primary fuel source. The original design of the project called for a Tampella Power gasification island and a 75-megawatt combined-cycle power plant with a Westinghouse 251B combustion turbine. At full production, the power plant would require nearly 350,000 tons of alfalfa stem material per year.

In late 1996, NSP selected MnVAP's biomass gasification combined-cycle project for negotiation of a PPA. MnVAP and NSP executed an MOU that outlined the terms to be incorporated in a power purchase agreement. By the end of 1997, MnVAP executed a long-term PPA with NSP. It was expected that this would provide long-term project viability. Execution of the PPA justified accelerated development work to prepare for financial closing and start of construction.

Phase I of the cooperative agreement provided DOE funds on a cost-shared basis to complete work in seven major project task areas. Each task area supported completion of items necessary for the MAP Project to reach financial closing and start construction; however there was insufficient time to begin commercial operations before the end of the calendar year 2001, the date by which NSP was required to bring biomass resources on line. Most tasks were completed, or were progressing well, but development work was suspended prior to financial closing de to a combination of events precipitated largely by regulatory delays.

Summary of Lessons Learned: Minnesota Agri-Power Project

1. Vendor Guarantees and Warranties: If plant configuration has not been tested, and/or if the feed has not been tested, then extended pilot testing is required (1000 - 2000 hours at steady state conditions) to develop vendor confidence leading to guarantees and warranties for commercial operation.

2. Pilot Plant Experience: Such testing may be doubly important when guarantees and warranties are needed from "downstream" unit operation vendors such as gas clean-up, gas turbine and stearn turbine original equipment manufacturers.

3. Project Scale-Up: A scale-up of ten times is too large to incorporate guarantees and warranties for untested processing steps or combinations of unit operations.

4. Project Financing: Developmental projects are inherently risky, requiring the development of creative approaches to investment and financing arrangements.

5. Entering New Markets: A marketing plan and study of existing markets for agriculturally-based, and other potential feedstock products must be developed. Expect resistance (political and economic) from current market suppliers.

6. Feedstock Suitability and Flexibility: Criteria for suitability of feedstocks for electrical conversion need to be developed. If possible, the conversion system should be designed to handle multiple feedstocks.

7. Technical Readiness: DOE needs to perform in-depth reviews of the technical status of development in relation to the proposed commercial project to better estimate the technical/commercial feasibility of the project. At a minimum, the project technical development time and cost should be reviewed in detail.

8. Reviews Prior to Award: A detailed technical review is required at the solicitation technical review stage to identify technology readiness for commercialization, rather than addressing such issues after agreements have been reached and project timing and costs have been contractually set.

Success Factors

Successful commercial implementation of technology is dependent on a wide range of positive and negative drivers. A preliminary analysis was performed that identified drivers in the areas of policy, corporate policy, regulation, legal, infrastructure, and technology, which resulted in a preliminary methodology for ranking relative importance. The analysis methodology involves development of an estimate of the impact of drivers on CHP systems (high, medium, low), the relative importance of each driver, and the probability of the driver occurring by 2020. Multiplying the three factors gives a weighted probability of the impact. This weighted probability can be normalized to 100% and ordered in terms of numerical importance. An example of the rating of drivers was estimated by the authors to demonstrate the methodology. Eventually, it would be desirable to ask a group of experts in the area to provide independent estimates of factors, and then develop a group evaluation of drivers. The example positive and negative drivers are given in Table 4-5. Table 4-6 presents a summary of key drivers, ranked by weighted probability.

Seventy-five percent of the positive drivers are given by 10 factors in the categories of technology, corporate policy, regulation and finance. The top three positive factors are the technology maturity of combustion and cofiring systems, the corporate need for CHP , and Federal mandates such as PURPA. Seventy-five percent of the negative drivers are given by nine factors in the categories of finance, corporate policy, and legal. The top three negative factors are lack of feedstock infrastructure, the cost of products compared to traditional sources, a corporate resistance to new technology introduction.

A qualitative comparison of key success factors relative to coal and natural gas was made and is presented in table 4-7. In general, biomass systems compare favorably with new coal facilities, especially in the area of environmental impact. In general, biomass systems do not compare favorably with natural gas systems, except in the area of environmental impact.

DRIVERS FOR BIOMASS CHP SYSTEMS

Ref	Category	DRIVERS	A (H,M,L) (5,3,1) Impact on CHP systems	B (1 to 20) Relative Importance	C (1-100%) Probability of Occurring by 2010	A x B Importance x Impact	A x B x C Weighted Probability of Impact	Weighted Probability % of Total	Weighted Cumulative Probability % of Total
		POSITIVE DRIVERS							
A	Policy	National Security (Domestic Sourcing Rulings)	5	10	25%	50	12.5	2.2%	2.2%
B	Regulation	Air Emissions Controls (National, State)	5	10	75%	50	37.5	6.7%	9.0%
C	Policy	State Programs for RE	5	15	25%	75	18.8	3.4%	12.4%
D	Finance	Federal Tax Incentives for RE	5	20	25%	100	25.0	4.5%	16.9%
E	Regulation	Federal Mandates, e.g., PURPA, RPS	5	20	50%	100	50.0	9.0%	25.8%
F	Infrastructure	Transmission Bottlenecks / Disruptions	3	10	25%	30	7.5	1.3%	27.2%
G	Regulation	Distributed Energy Certification Standards	3	5	100%	15	15.0	2.7%	29.9%
H	Regulation	Electricity Wheeling	3	10	50%	30	15.0	2.7%	32.6%
I	Policy	Climate Change Policy (international)	1	5	50%	5	2.5	0.4%	33.0%
J	Finance	Fuel Price Volatility (coal, oil, natural gas)	3	15	50%	45	22.5	4.0%	37.1%
K	Finance	Fuel Supply Disruptions (Oil, Natural Gas)	3	20	25%	60	15.0	2.7%	39.8%
L	Corp Policy	Corporate Energy Autonomy	3	5	50%	15	7.5	1.3%	41.1%
M	Corp Policy	Corporate RE Mandate	5	20	25%	100	25.0	4.5%	45.6%
N	Corp Policy	Corporate Use/Need for CHP	3	20	100%	60	60.0	10.8%	56.4%
O	Finance	Use of Existing Residues	5	10	100%	50	50.0	9.0%	65.4%
P	Technology	Alternative Future Uses, e.g., SYNGAS	3	5	100%	15	15.0	2.7%	68.1%
R	Finance	Cost of Fuel - Stability	3	10	75%	30	22.5	4.0%	72.1%
S	Corp Policy	Support of Local Economy - Indigenous Feed	1	5	100%	5	5.0	0.9%	73.0%
T	Finance	Low Interest Rates	5	5	10%	25	2.5	0.4%	73.5%
U	Finance	Cofiring Capital Cost	3	15	100%	45	45.0	8.1%	81.6%
V	Finance	Production of Export Electricity	3	10	50%	30	15.0	2.7%	84.3%
W	Technology	Technology Maturity, Combustion and Cofiring	5	15	100%	75	75.0	13.5%	97.8%
X	Legal	Environmental Community Acceptance	5	5	50%	25	12.5	2.2%	100.0%
		Average for Positive Factors	3.70	11.52		45.0			
		Sum for Positive Factors					556.3	100.0%	

Drivers for Biomass CHP Systems

			A	B	C	A x B	A x B x C		
			(H,M,L) (5,3,1) Impact on CHP systems	(1 to 20) Relative Importance	(1-100%) Probability of Occurring by 2010	Importance x Impact	Weighted Probability of Impact	Weighted Probability % of Total	Weighted Cumulative Probability % of Total
		DRIVERS							
		NEGATIVE DRIVERS							
AA	Corp Policy	Resistance to Change	5	20	80%	100	80.0	9.1%	9.1%
BB	Corp Policy	Corporate Experience	5	20	50%	100	50.0	5.7%	14.7%
CC	Finance	Feedstock Infrastructure	5	20	100%	100	100.0	11.3%	26.1%
DD	Finance	Feedstock Cost	3	15	80%	45	36.0	4.1%	30.1%
EE	Finance	Feedstock Transportation	3	10	50%	30	15.0	1.7%	31.8%
FF	Finance	Competition for Feedstock	5	20	50%	100	50.0	5.7%	37.5%
GG	Technology	Process Efficiency	3	10	95%	30	28.5	3.2%	40.7%
HH	Finance	Capital Cost, Economy of scale	5	15	95%	75	71.3	8.1%	48.8%
II	Finance	Operating Costs	5	15	95%	75	71.3	8.1%	56.9%
JJ	Finance	Cost of Products	5	20	95%	100	95.0	10.8%	67.6%
KK	Finance	Higher Interest Rates	3	10	90%	30	27.0	3.1%	70.7%
LL	Finance	Low Coal Prices	1	15	95%	15	14.3	1.6%	72.3%
MM	Finance	Low Oil and Gas Prices	1	15	25%	15	3.8	0.4%	72.7%
NN	Regulation	Permitting / Siting Problems	5	20	50%	100	50.0	5.7%	78.4%
OO	Legal	Environmental Community Opposition	5	20	75%	100	75.0	8.5%	86.9%
PP	Corp Policy	Power Purchase Agreements	3	20	95%	60	57.0	6.5%	93.4%
QQ	Regulation	Cost of Environmental Controls	3	15	100%	45	45.0	5.1%	98.5%
RR	Technology	Technology Immaturity - Gasification	1	15	90%	15	13.5	1.5%	100.0%
		Average for Negative Factors	3.67	16.39		63.056			
		Sum for Negative Factors					882.5		

KEY SUCCESS FACTORS FOR BIOMASS CHP SYSTEMS

Ref	Category	KEY DRIVERS	Weighted Probability % of Total	Weighted Cumulative Probability % of Total
		POSITIVE FACTORS		
W	Technology	Technology Maturity, Combustion and Cofiring	13.5%	13.5%
N	Corp Policy	Corporate Use/Need for CHP	10.8%	24.3%
E	Regulation	Federal Mandates, e.g., PURPA, RPS	9.0%	33.3%
O	Finance	Use of Existing Residues	9.0%	42.2%
U	Finance	Cofiring Capital Cost	8.1%	50.3%
B	Regulation	Air Emissions Controls (National, State)	6.7%	57.1%
D	Finance	Federal Tax Incentives for RE	4.5%	61.6%
M	Corp Policy	Corporate RE Mandate	4.5%	66.1%
J	Finance	Fuel Price Volatility (coal, oil, natural gas)	4.0%	70.1%
R	Finance	Cost of Fuel - Stability	4.0%	74.2%
C	Policy	State Programs for RE	3.4%	77.5%
G	Regulation	Distributed Energy Certification Standards	2.7%	80.2%
H	Regulation	Electricity Wheeling	2.7%	82.9%
K	Finance	Fuel Supply Disruptions (Oil, Natural Gas)	2.7%	85.6%
P	Technology	Alternative Future Uses, e.g., SYNGAS	2.7%	88.3%
V	Finance	Production of Export Electricity	2.7%	91.0%
A	Policy	National Security (Domestic Sourcing Rulings)	2.2%	93.3%
X	Legal	Environmental Community Acceptance	2.2%	95.5%
F	Infrastructure	Transmission Bottlenecks / Disruptions	1.3%	96.9%
L	Corp Policy	Corporate Energy Autonomy	1.3%	98.2%
S	Corp Policy	Support of Local Economy - Indigenous Feed	0.9%	99.1%
I	Policy	Climate Change Policy (international)	0.4%	99.6%
T	Finance	Low Interest Rates	0.4%	100.0%

Ref	Category	KEY DRIVERS	Weighted Probability % of Total	Weighted Cumulative Probability % of Total
		NEGATIVE FACTORS		
CC	Finance	Feedstock Infrastructure	11.3%	11.3%
JJ	Finance	Cost of Products	10.8%	22.1%
AA	Corp Policy	Resistance to Change	9.1%	31.2%
OO	Legal	Environmental Community Opposition	8.5%	39.7%
HH	Finance	Capital Cost, Economy of scale	8.1%	47.7%
II	Finance	Operating Costs	8.1%	55.8%
PP	Corp Policy	Power Purchase Agreements	6.5%	62.3%
BB	Corp Policy	Corporate Experience	5.7%	67.9%
FF	Finance	Competition for Feedstock	5.7%	73.6%
NN	Regulation	Permitting / Siting Problems	5.7%	79.3%
QQ	Regulation	Cost of Environmental Controls	5.1%	84.4%
DD	Finance	Feedstock Cost	4.1%	88.4%
GG	Technology	Process Efficiency	3.2%	91.7%
KK	Finance	Higher Interest Rates	3.1%	94.7%
EE	Finance	Feedstock Transportation	1.7%	96.4%
LL	Finance	Low Coal Prices	1.6%	98.0%
RR	Technology	Technology Immaturity - Gasification	1.5%	99.6%
MM	Finance	Low Oil and Gas Prices	0.4%	100.0%

KEY SUCCESS FACTORS

	Relative to Coal	Relative to N. Gas
Construction/Installation		
Experience	NA	NA
Capital Cost	+	--
Predictability of Schedule	NA	NA
Space/Footprint, including acreage	0	--
Operating		
Labor Costs	0	++
Maintenance Costs	0	-
System Reliability	-	-
Feedstock		
Price		
Residues	+ / 0	0/-
Dedicated Feeds	--	--
Availability		
Reliability of Supply	--	--
Quality	-	--
Environmental		
Air Emissions	+	--
Green House Gases	++	++
Solid Wastes	+	--
Liquid Wastes	0/+	0/-
Permitting	+	-
Waste Reduction	++	++
Economic		
Financing		
Power Purchase Agreement		
Tax Incentives		
Regulatory Policy		

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